Arnold Schwarzenegger
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# INTERMITTENCY ANALYSIS PROJECT: APPENDIX B IMPACT OF INTERMITTENT GENERATION ON OPERATION OF CALIFORNIA POWER GRID

PIER FINAL PROJECT REPORT

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# Executive Summary

California has one of the most diverse electricity supply systems in the nation with a large potential to generate electricity from renewable sources, such as wind, geothermal, biomass, hydroelectric and solar. With progressive renewable policies, the challenge facing the state will be how best to integrate and manage renewable energy resources with traditional generation while ensuring a reliable electricity system.

## Study Overview

The Intermittency Analysis Project was tailored to present a statewide perspective of the transmission infrastructure and services needed to accommodate the renewable penetration levels defined in the state's renewable energy policy. The Intermittency Analysis Project was technical and was intended to provide a 2020 perspective on potential operational needs and impacts to meet future growth and demand.

This report documents the last stage of the multi-stage Intermittency Analysis Project. Preceding stages included:

- Evaluation of past, present, and future wind turbine technologies, and their effect on transmission system operation and performance, by BEW Engineering, Inc.
- Assessment of worldwide experience with integrating large penetrations of wind energy, by Kevin Porter of Exeter Associates, Inc.
- Development of future renewable energy scenarios and evaluation of the effects on transmission reliability, by Davis Power Consultants.

The future renewable generation scenarios developed by Davis Power Consultants were critical inputs to the analysis documented in this report. Data provided from Davis Power Consultants included:

- Detailed lists of individual renewable generating plants and their site/rating for each scenario studied, consistent with California's Renewables Portfolio Standard goals and locations of renewable resources, and
- Power–flow datasets with conventional generation, renewable generation, and transmission system build-outs for each scenario, consistent with the projected California peak load–level.

The Intermittency Analysis Project considered four types of renewable generation to meet California's renewable energy goals: wind, solar, geothermal, and biomass. Wind and solar generation are intermittent, as their energy sources are not dispatchable:

- The power produced by a wind plant varies as a function of wind speed.
- The power produced by solar generation varies as the intensity of the sunlight.

Geothermal and biomass resources are dispatchable and, therefore, are not intermittent generation.

Four scenarios were analyzed, as follows:

- 2006 Base Case
  - Existing 2006 transmission system with existing mix of generation, including 2,100 megawatts (MW) of wind and 330 MW of solar.
- 2010 Tehachapi Case with 20 percent renewable energy (designated 2010T)
  - 7,500 MW wind and 1,900 MW solar in California.
  - Includes 4,200 MW of new and existing wind generation at Tehachapi, with new 500 kilovolt (kV) transmission to support it.
- 2010 Accelerated Case with 33 percent renewable energy (designated 2010X)
  - 12,500 MW wind and 2,600 MW solar in California.
  - Assumes interim infrastructure with most of the 2020 intermittent renewable generation.
- 2020 Case with 33 percent renewable energy
  - 12,700 MW wind and 6,000 MW solar in California.

General Electric Energy Consulting evaluated the effect of intermittent generation (wind and solar) on the operation of the California power grid. The objectives were:

- Evaluate California grid operation with increasing levels of intermittent generation, up to the renewable policy levels of wind and solar and using the four scenarios developed for that purpose.
- Identify and quantify system performance and any operational problems (for example, load following, regulation, operation during low-load periods).
- Identify and evaluate possible mitigation methods.

The evaluation covered time scales involved in grid operation and included the following specific types of analysis for each scenario:

- Statistical analysis of variability due to system load, as well as wind and solar generation over time frames (hourly, 5-minute, 1-minute).
- Production cost simulations of the California power grid and the Western Electricity Coordinating Council, using the Multi-Area Production Simulation program, to evaluate hour-by-hour grid operation for 3 years with different wind and load profiles.
- Quasi-steady-state simulations, using Positive Sequence Load Flow program, to evaluate minute-by-minute time-sequenced power flows for the entire Western Electricity Coordinating Council grid over several hours, to quantify grid performance trends and to investigate potential mitigation measures.

The effect of wind and solar forecasting in grid operations and unit commitment were also evaluated.

## Conclusions

Two scenarios (2010T and 2020) represented steps on an expected trajectory to meet California's renewable generation goal. The artificially accelerated 2010X scenario was developed to increase system stress and represents the most challenging study condition. However, the conclusions and recommendations presented in this section apply to all scenarios, not just the most challenging. They are intended to enable consistent, sustained renewable growth through 2020.

The 2010X scenario examined a total of 19,800 MW of renewables in California, including 12,500 MW of wind generation, 2,600 MW of solar, 1,000 MW of biomass, and 3,700 MW of geothermal. This scenario represents a stressed condition designed to test the system with more renewables than projected for 2010.

This level of renewable generation can be successfully integrated into the California grid provided appropriate infrastructure, technology, and policies are in place. Specifically, this successful integration will require:

- Investment in transmission, generation, and operations infrastructure to support the renewable additions.
- Appropriate changes in operations practice, policy, and market structure.
- Cooperation among all participants, California Independent System Operator (California ISO), investor–owned utilities, renewable generation developers and owners, non-Federal Energy Regulatory Commission jurisdictional power suppliers, and regulatory bodies.

## Recommendations

The study scenarios represent stages along a trajectory to meet California's renewable generation goal. The following recommendations are a set of targets, actions, and policies designed to ensure successful integration of significant levels of intermittent renewable generation through 2020. The implementation of these recommendations should proceed with the renewable generation growth. Such evolutionary improvements will allow secure and economic integration at all stages along the renewable generation growth trajectory.

The challenge of accommodating substantial intermittent renewable generation is incremental to the challenge of serving existing and new load. Long–term planning must always consider requirements for generation and transmission and strike an appropriate balance between the two. Further, new considerations specific to renewable technologies must be included. Thus, the planning process must consider three major system components:

- Generation
- Transmission

- Renewable Technology

The recommendations presented below are grouped accordingly.

### Generation Resource Adequacy

The California Energy Commission, California Public Utilities Commission, and California ISO have ongoing processes to provide the generation infrastructure necessary to maintain reliable operation. The addition of both intermittent and non-dispatchable renewable resources to the California grid increases the requirement for generation resource flexibility. It is essential that this requirement for flexibility be included in the overall assessment and planning for resource adequacy. It is recommended that specific attributes of generation flexibility be inventoried, maintained, and increased. Where possible, quantitative targets are suggested; others may be adopted as circumstances and understanding changes. To avoid repetition, specific policy and technology recommendations are grouped with the most relevant performance issue. However, many recommendations could apply to a broader range of performance categories. Further, none of the recommendations are either self-sufficient or mutually exclusive. An appropriate combination of recommendations will be most successful.

*Minimum Load Operation.* The California grid should target a combination of in-state generating resources and power exchange capability/agreements with neighboring systems that allow operation down to a minimum net load (load minus wind minus solar) in the range of 18,000 MW to 20,000 MW. These targets will meet the long-term (2020) needs of the system and allow for operation with minimal curtailment of intermittent renewables.

> *Minimum Turndown.* Generating resources with lower minimum power output levels provide greater flexibility and allow successful operation at minimum load. New generating resources should be encouraged and/or required to have this capability; existing generation should be encouraged and/or required to upgrade their capability. A comparison of the load and net load (load-wind-solar) for the various scenarios shows that minimums are less with the intermittent generation on the system. The minimum system turndown capability will determine the amount of renewable generation curtailment that is necessary. A minimum of 20,000 MW is expected to result in curtailment during a few hundred hours per year for the expected growth trajectory.
>
> *Diurnal Start/Stop*. Another way to meet minimum load is to increase the amount of generation that is capable of reliable diurnal cycling. This will benefit the system by allowing the commitment of units that are economic at peak and shoulder loads, without requiring their non-economic operation at light load.
>
> *Load Participation*. Active participation by large loads, especially pumps, is another way to assure adequate flexibility. The pumps controlled by California Department of Water Resources are already participants in the energy market, but additional types of participation and cooperation could increase overall system flexibility. For example, additional investment in pumps, controls, or other load infrastructure to take advantage of light load energy pricing could be both economic and effective [8].

California should explore other means to encourage load shifting toward light load conditions. Various load shifting and storage technologies, such as cold storage (for example. for building cooling or inlet air cooling for gas peaking generation) hold promise and may prove to be economic. Arrangements that give the grid operator control over loads for a contractual consideration or rate reduction will be more attractive as penetration of intermittent renewables increases.

*Pumped Storage Hydro*. Use of pumped storage hydro facilities was shown to increase for the scenarios examined. The infrastructure and policy necessary to allow the best use of existing pumped storage hydro within California should be enhanced. Additional pumped storage hydro capability could also enhance system scheduling flexibility and will likely aid other flexibility attributes discussed below. This is particularly true when conventional hydro flexibility is low, due to unusually high run-off conditions.

*Hourly Schedule Flexibility.* The California grid should target a combination of in-state generating resources that provide a minimum level of scheduling flexibility. The anticipated load growth to 2020 will drive the overall system flexibility needs from the present level of about 4,300 megawatts per hour (MW/hr) to about 6,000 MW/hr. The additional variability and uncertainty associated with intermittent renewables will increase the amplitude of sustained load ramps (both up and down), and the frequency of generation starts and stops. For the expected renewables growth trajectory (2010T, 2020), the overall hourly flexibility requirement is expected to be about 130 MW/hr greater than that required for load alone. Under the artificially accelerated renewable expansion of the 2010X scenario, that incremental requirement is about 400 MW/hr.

During light load conditions, total requirements are smaller, but the relative impact of intermittent renewables is larger. The anticipated load growth to 2020 will drive the light load system flexibility needs from the present level of about 2,000 MW/hr up to about 3,000 MW/hr. For the expected renewables growth trajectory (2010T, 2020), the hourly light load flexibility requirement is expected to be about 1,000 MW/hr greater than that required for load alone.

*Hydro Scheduling*. Conventional hydroelectric generation plays a key role in light load schedule flexibility as well as load following and regulation. Economic operation will be enhanced by high hydro flexibility. Existing flexibility should be maintained at least, and investments to increase maneuverability should be considered. A documented inventory of capability is important. California should periodically examine the amount and type of hydro constraints, and evaluate investments or contractual mechanisms for cost-effective relief of those constraints.

*Faster Start/Stop.* Uncertainties in forecasts create a somewhat different flexibility requirement. Even with state-of-the-art wind forecasting, both day-ahead and hour-ahead net load forecast uncertainties will increase due to intermittent renewables. With an increased risk of an actual net load significantly different from the forecast net load, short-notice start/stop capability during daily operation will be an important part of the redispatch needed to balance generation and load. The California grid should target sufficient in-state generating resource capability to meet day-ahead forecast errors in the range of ±5,000 MW of generation capacity and hour-ahead forecast errors in the range of ±2,000 MW of generation capacity. Overall, this represents about double the present level of day-ahead load forecast error and about 20 percent more than the present hour-ahead load forecast error.

During lighter load periods, the net load forecast error may be three times the load–alone forecast error in the day-ahead forecast. The targets recommended above will also be sufficient for light load conditions.

*Multi-Hour Schedule Flexibility.* Flexibility targets should also address periods of sustained load increases and decreases. The recommended targets are for the California grid to have enough resources to meet a maximum morning load increase of 12,000 MW over three hours and a maximum evening load decrease of 14,000 MW over three hours. This represents an increase of about 1,000 MW over the capability needed to meet the load alone.

*Load Following Capability*. The California grid should target a combination of in-state generating resources that provide a minimum level of generation ramping capability, both up and down. On average, the system should maintain on the order of +/-130 MW/minute for a minimum of 5 minutes. This is about a 10 MW/minute increase over the requirement due to load alone.

During light load conditions, approximately 70 MW/minute of down load-following capability are required. Up load-following requirements are lower. The load-following capability should be subject to economic dispatch from the system operators. Load following duty should not be shifted to units providing regulation.

*Import/Export Scheduling*. The California grid should recognize that economic incorporation of substantial in-state renewables will inevitably involve significant displacement of imported energy. Regulatory and contractual arrangements for imports and exports should be structured such that the value of scheduling flexibility is recognized, allowed, and appropriately compensated. In particular, California should allow schedule changes to occur more frequently and at times other than on the hour.

*Regulation Capability*. The California grid should target a combination of in-state generating resources that provide a minimum level of regulation capability. The California ISO currently procures regulation in the range of 300 MW to 600 MW. The procured amount varies substantially over all load levels. The impact of intermittent renewables on regulation (20 MW) is considerably less than the normal variability in the amount procured. However, regulation resources will continue to be important. Therefore, the California grid should at least maintain the current level of regulation capability. This level of regulation should allow the state to continue to satisfy their regulatory obligations for interchange and frequency control, such as the North American Electric Reliability Council Control Performance Standard 2 compliance should be continually scrutinized as intermittent renewables are added to the grid to refine regulation requirements and procurement.

*Regulation Technologies*. California should consider using technologies beyond conventional generation to provide regulation. The earlier discussion about load participation in schedule flexibility applies here as well. Functional requirements for loads to provide regulation are different from those for generation. Given a suitable regulatory and market structure, however, it is likely that other technologies and participants will emerge to provide the required services. Examples include some types of storage technology, such as variable speed pumped hydro and the latest flywheel energy storage systems. Policy and market structure should encourage diversity of participants in providing ancillary services, and technical specifications for performance should be sufficiently flexible to allow the introduction of new technologies.

*Non-Technical Resource Adequacy Considerations.* The preceding recommendations were aimed at securing the technical capabilities necessary for successful integration of intermittent renewables. The following items address policy and commercial considerations.

*Market Design.* It must be recognized that while operational flexibility is valuable to the grid, it currently holds little attraction for power suppliers. Deeper turnback, more rapid cycling and load following, and more frequent starts and stops all impose significant costs and revenue reductions on the suppliers. Market and regulatory structures must recognize the value of these flexibility features. Policy changes may include a combination of expanded ancillary services markets, incentives, and mandates.

*Contractual Obligations.* Much of the analysis presented in this report is based on the presumption that the grid is operated rationally – that is, the available generation resources are used as efficiently and economically as possible. The analysis did not include historical constraints, such as long term contractual obligations, that force the system to run less efficiently than possible. New contracts under consideration, existing long-term contracts up for renewal, or indeed any existing contracts that could be renegotiated should be reviewed with all of the preceding resource adequacy recommendations in mind. The California grid must maintain operational flexibility, and to do so, it must have not only the physical resources necessary, but also the business and contractual arrangements necessary to enable the rational use of those physical resources.

*Retirements.* Generating plant retirements that were firmly scheduled when the databases were assembled were incorporated into this study. However, increased competition from new resources, renewable or otherwise, will tend to push marginally profitable generating resources out of business. Such speculative, economic retirements were not considered in the study. Successful implementation of the recommendations above will ensure that resources with the necessary flexibility are available. In addition, it is recommended that retirements be projected, monitored, and evaluated during the resource planning process.

*Inventory.* During this study, it was noted that generator characteristics and capabilities (for example, minimum turn–down, ramp–rate capability) were not always known with sufficient detail or certainty. Some degree of uncertainty is inevitable. However, with the increased need for resource flexibility, California should implement a program to measure, verify, and catalogue the flexibility characteristics of the generation resources. A program similar to the Western Electricity Coordinating Council generator dynamic testing might prove suitable.

### *Transmission Infrastructure*

The addition of thousands of MW of new generation of any variety will require expansion of the transmission system. This study included the addition of enough bulk transmission necessary for connection of the new renewables to the grid as determined and documented by Davis Power Consultants [6]. However, it was not a detailed transmission study and is not a substitute for one. Policies must recognize that local problems might develop, and enable the necessary transmission additions. Practice and policy that correct problems and strike a balance between infrastructure investment and congestion are necessary. To an appreciable extent, this observation holds for all transmission planning and all generation additions. California can economically benefit from changes in planning and operation of the transmission infrastructure by recognizing the locational and variable nature of intermittent renewables. The following recommendations are specific to these needs.

*Existing Constraints.* California has existing infrastructure that contributes substantially to the secure and economic operation of the grid with high levels of intermittent renewables. In some circumstances, the use of that infrastructure for systemwide benefit is constrained by local transmission limitations. One example of such a constraint is the occasional inability of Helms pumped storage hydro to reach full pumping power. Planning and policy should recognize and enable correction of such local limitations.

*Rating Criteria.* Wind generation is variable, and the spatial differences between plants substantially effects the coincident production of power from those plants. Clearly, a wind plant will reach rated output for many hours per year. Thus, normal planning criteria requires sufficient capability, such as thermal rating, on the transmission interconnection dedicated to that plant to accommodate rated power output.

However, as more wind plants vie for access to specific transmission corridors, it will be increasingly unlikely that all wind plants will simultaneously reach their maximum output. Note that in three years of data, all wind plants in this study never simultaneously reached maximum output. And the 12,500 MW of wind generation exceeded 10,000 MW of production less than 1 percent of the time. Thus, transmission planning to accommodate multiple wind plants should consider their spatial differences and the statistical expectation of simultaneous high power output levels. Plants close together will generally require transmission capability equivalent to the aggregate rating of the plants. Plants that are farther apart may require less transmission capability. Hence, it is not necessary to guarantee sufficient rating on the bulk transmission infrastructure to accommodate all wind projects at full output. Existing criteria should be sufficient to provide this planning flexibility.

*Technology.* Policy should reward investment in technology to maximize use of transmission infrastructure for renewables. Such policies should recognize that wind generation is a relatively poor resource for capacity and that creative use of technology may optimize use of transmission. Regulatory and contractual practice should allow technologies such as real-time line ratings, controls that manage output from intermittent renewable resources, local short-term forecasting, and other non-standard approaches to balance renewable energy delivery with transmission infrastructure costs.

### Renewable Generation Technology, Policy, and Practice

With significant levels of intermittent renewable generation, operation may be challenging at extremely light load levels, under a constrained transmission grid, or with high wind volatility. Under these conditions, renewable generation must participate in overall grid control. The following recommendations are specific to renewable technology and are aimed at assuring that intermittent renewables play an active and positive role in the secure and economic operation of the grid.

*Curtailment.* Under the rare occasions of coincident minimum load, high wind generation, and low conventional hydro flexibility, it must be possible to curtail intermittent renewables. The grid operator should have the ability to order such a reduction in production. Regulatory and contractual arrangements for intermittent renewables should be structured such that curtailments are recognized, allowed, and appropriately compensated. Ramp rate controls could also be considered.

*Ancillary Services.* Intermittent renewables may be able to provide ancillary services that are both valuable and economic under some operating conditions. For example, wind generation can provide frequency regulation. Such functionality is a requirement in some regions [10]. Regulatory and contractual arrangements for intermittent renewables should be structured such that providing such services are recognized, allowed, and appropriately compensated.

*Forecasting*. Successful and economic operation of the California grid requires wind and solar forecasting. This study verified substantial benefits from the use of state-of-the-art day-ahead forecasting in the unit commitment process. Substantial benefits are expected for improvements in both longer–term (multi-day) and short-term (hours and minutes ahead) forecasting. Investment and policy must encourage development of high fidelity intermittent renewable forecasting for all intermittent renewable generation in the state.

*Monitoring*. The wind production profiles used in this study are based on historical weather data and sophisticated computer models. Recorded data from real operating experience will be invaluable in refining operating practice, performance, and flexibility requirements. Time synchronized production and meteorological data from many plants will provide validation or correction of the trends and results predicted by this study. They will show the benefits and limitations of spatial differences, meso-scale modeling, and various wind plant controls. It is recommended that California continue and expand, as necessary, programs to monitor, analyze, and disseminate performance information regarding grid operations and planning for intermittent renewables.

The targeted levels of renewable generation can be successfully integrated into the California grid provided appropriate infrastructure, technology, and policies are in place.

# 1.0 Introduction

California has one of the most diverse electricity supply systems in the nation with a large potential to generate electricity from renewable sources, such as wind, geothermal, biomass, hydroelectric and solar. With progressive renewable policies as in the Renewables Portfolio Standard (RPS) and state Energy Action Plan [1], the challenge facing the state will be how best to integrate and manage renewable energy resources with traditional generation while ensuring a reliable electricity system.

## 1.1. Challenges

With policy targets of 20% renewable energy by 2010 and 33% by 2020, a few of the main challenges facing the state include:

- Building sufficient transmission infrastructure to support and sustain the development envisioned for 2020
- Balancing the need to integrate increasing levels of renewable energy while minimizing adverse impacts on the surrounding environment
- Developing tools with the industry to properly integrate variable renewable resources including wind and solar

## 1.2. Background

The Intermittency Analysis Project (IAP) sought to address the following questions:

- What are the impacts of increasing renewable energy projects on system reliability and dispatchability, with a particular focus on wind and solar energy?
- What will the future system look like and where will the resources come from?
- How will the future grid need to respond? Will it respond by market structure, services, or technologies?

The IAP was tailored to present a state-wide perspective of the transmission infrastructure and services needed to accommodate the renewable penetration levels defined in the state's renewable energy policy. The IAP was technical in nature and was intended to provide a year-2020 perspective on potential operational needs and impacts to meet future growth and demand. As a result, certain assumptions were made on technology availability, system conditions and constraints, as well as market constraints.

In this project, power flow and production cost modeling were conducted to establish the operational baseline of the California grid as of 2006 and to develop the renewable resource mixes for the 2010 and 2020 scenarios. Renewable portfolio mixes as well as the transmission needed to interconnect the resources were evaluated in the scenarios based on a transmission benefit criteria. The modeling built and expanded on previous California Energy Commission (Energy Commission) funded transmission studies that focused on connecting statewide renewable resource potential and the associated transmission considerations.

This project built upon work that was completed for the Energy Commission as part of the 2005 Integrated Energy Policy Report (IEPR) process [2]. More information may be found related to IEPR on the Commission website (www.energy.ca.gov). The IAP effort leveraged work conducted by the California Wind Energy Collaborative (CWEC) [3], the Consortium for Electric Reliability Technology Solutions (CERTS) [4], and the Strategic Value Analysis (SVA) work by Davis Power Consultants (DPC). Under the SVA project, Public Interest Energy Research (PIER) and DPC assessed the availability of renewable resources and defined an approach that minimizes transmission infrastructure changes and maximizes benefits for integrating renewables onto the California grid by avoiding congestion. Availability of inter-state and intra-state renewable resources and transmission requirements were also modeled using the SVA approach to alleviate, or at least minimize, transmission constraints [5].

## 1.3. Intermittent Generation Definition

The IAP considered four types of renewable generation to meet California's renewable energy goals; wind, solar, geothermal, and biomass. Wind and solar generation are intermittent, as their energy sources are not dispatchable:

- The power produced by a wind plant varies as a function of wind speed
- The power produced by solar generation varies as the intensity of the sunlight.

Geothermal and biomass resources are dispatchable, and therefore are not intermittent generation.

## 1.4. Overview of Project Objectives, Tasks and Participants

This report documents the last stage of the multi-stage IAP. Preceding stages included:

- Evaluation of past, present, and future wind turbine technologies, and their impact on transmission system operation and performance, by BEW Engineering, Inc.
- Assessment of worldwide experience with integrating large penetrations of wind energy, by Kevin Porter of Exeter Associates, Inc.
- Development of future renewable energy scenarios consistent with California's RPS, and evaluation of the impacts on transmission reliability, by Davis Power Consultants (DPC).

The future renewable generation scenarios developed by DPC were critical inputs to the analysis documented in this report. Figure 1 is a flowchart showing the major tasks that assessed grid impacts and mitigation methods for intermittency, as well as the tasks that produced the scenarios and data necessary for that analysis. DPC assessed the potential for future renewable resources (wind, solar, geothermal, biomass) and developed a series of scenarios with increasing levels of renewable generation, consistent with the goals of the California RPS. All of the renewable generation was located inside California. The DPC team also developed corresponding transmission expansion plans for each renewable generation scenario.

Thus, the results of the DPC task included the following for each scenario:

- Detailed list of individual renewable generating plants and their site/rating, consistent with California's RPS goals and locations of renewable resources, and
- Power flow datasets with conventional generation, renewable generation, and transmission system build-outs consistent with the projected California peak load level.

The scenarios are:

- 2006 Base Case
  - Existing 2006 transmission system with existing mix of generation, including 2,100 megawatts (MW) of wind and 330 MW of solar.
- 2010 Tehachapi Case with 20% renewable energy (designated 2010T)
  - 7,500 MW wind and 1,900 MW solar in California.
  - Includes 4,200 MW of new and existing wind generation at Tehachapi, with new 500 kilovolts (kV) transmission to support it.
- 2010 Accelerated Case with 33% renewable energy (designated 2010X)
  - 12,500 MW wind and 2,600 MW solar in California.
  - Assumes interim infrastructure with most of the 2020 intermittent renewable generation.
- 2020 Case with 33% renewable energy
  - 12,700 MW wind and 6,000 MW solar in California.

Complete results of this portion of the IAP are documented in the report "*Intermittency Impacts of Wind and Solar Resources on Transmission Reliability*", by Davis Power Consultants [6].

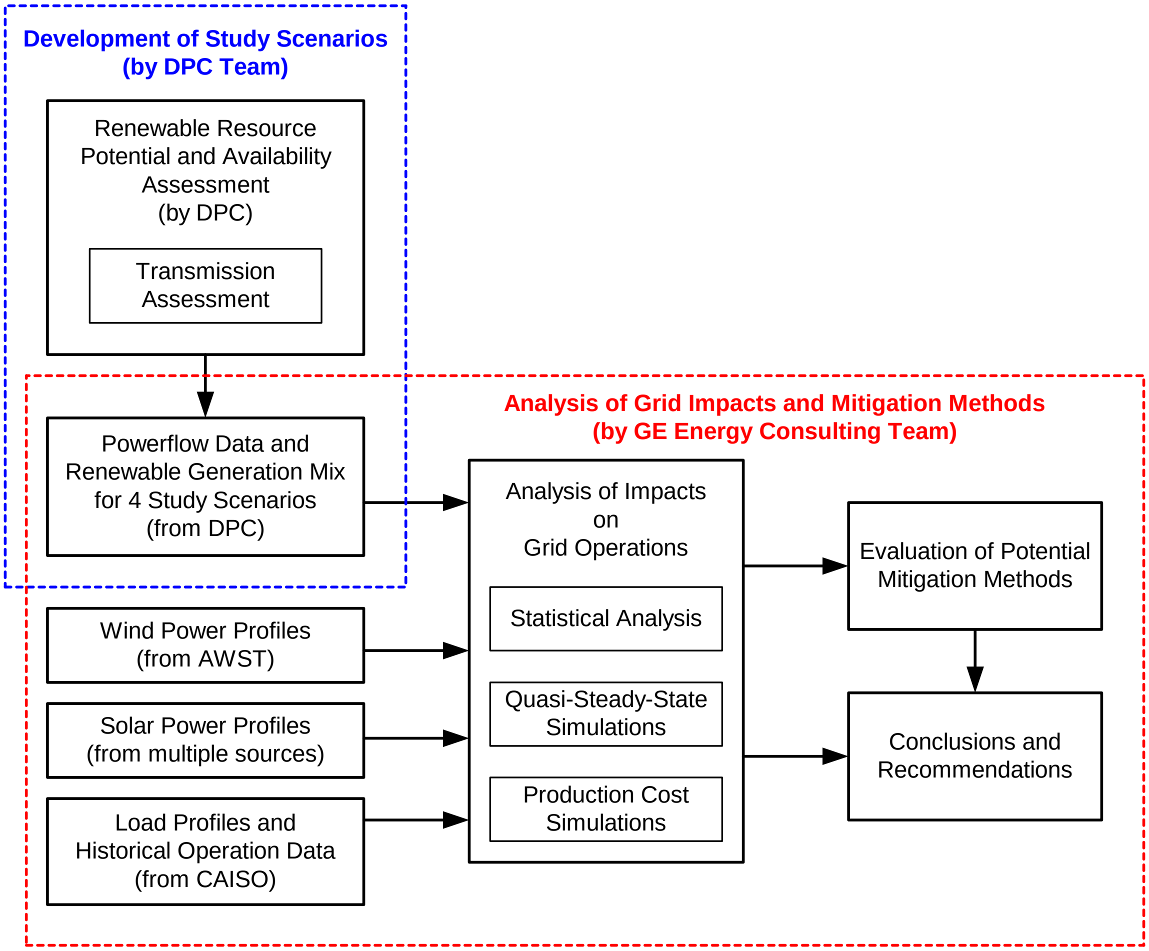


**Figure 1. Flowchart of Intermittency Analysis Project.**

Note: AWST = AWS Truewind, LLC.; CAISO = California Independent System Operator; GE Energy = General Electric Energy Consulting.

General Electric Energy Consulting,(GE) evaluated the impact of intermittent generation (wind and solar) on the operation of the California power grid. The objectives were:

- Evaluate California grid operation with increasing levels of intermittent generation, up to the renewable policy levels of wind and solar and using the four scenarios developed for that purpose.
- Identify and quantify system performance and any operational problems (e.g., load following, regulation, operation during low-load periods).
- Identify and evaluate possible mitigation methods.

The evaluation covered multiple time scales involved in grid operation, as illustrated in Figure 2, and included the following specific types of analysis for each scenario:

- Statistical analysis of variability due to system load, as well as wind and solar generation over multiple time frames (hourly, 5-minute, 1-minute).

- Production cost simulations of the California power grid and the Western Electricity Coordinating Council (WECC), using General Electric's Multi-Area Production Simulation (GE-MAPS™) program, to evaluate hour-by-hour grid operation for 3 years with different wind and load profiles.
- Quasi-steady-state simulations, using Positive Sequence Load Flow (PSLF) program, to evaluate minute-by-minute time-sequenced power flows for the entire WECC grid over several hours, to quantify grid performance trends and to investigate potential mitigation measures.

The impact of wind and solar forecasting in grid operations and unit commitment were also evaluated.

This report presents the results of that analysis, as well as conclusions and recommendations drawn from the results.

## 1.5. Participants

In conducting this project, GE Energy Consulting collaborated with several other organizations on the following essential tasks:

- AWS TrueWind – wind profile data for existing and future wind generation sites [7]
- Rumla – production cost model data for the California power grid and WECC.
- California Independent System Operator (California ISO) – load profiles and historical operation data for the California power grid.
- Solar data was obtained from multiple sources, including California ISO, the University of California at-Davis, the National Renewable Energy Laboratory (NREL), Stirling Energy Systems, the California Public Utilities Commission (CPUC) Self Generation Incentive Program, and Atmospheric Research Science Center at the State University of New York at-Albany.

GE Energy Consulting gratefully acknowledges the valuable contributions of all of these organizations. This project could not have been performed without them.

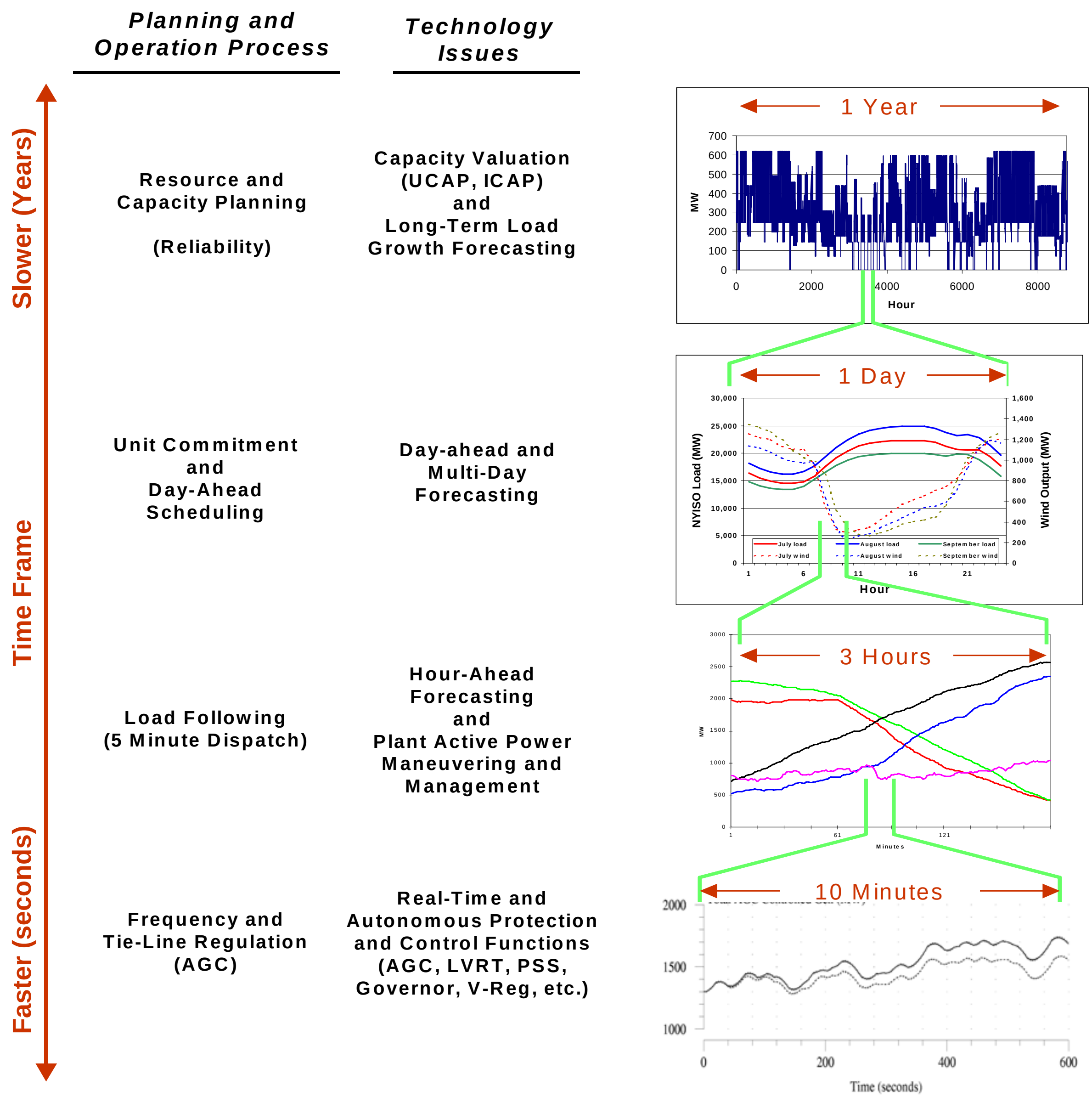


**Figure 2. Time Scales for Grid Planning and Operations.**

UCAP = uniform capacity, ICAP = installed capacity, AGC = automated generator control, LVRT = low voltage ride through, PSS = power system stabilizer, V-Reg = voltage regulation

# 2.0 Study Approach

The overall study approach is outlined in this section. The study scenarios, types of analysis, data provided, and terminology are all described below.

## 2.1. Study Scenarios

The renewable generation mix for each of the four study scenarios is summarized in Table 1.

The various scenarios can be described in terms of increasing levels of renewable generation penetration. But the definition of penetration can be confusing. Many Renewable Portfolio Standards (RPS) use penetration to describe the percent of *energy* to be provided by all of the *renewable* generation, including wind, solar, geothermal, biomass and sometimes hydroelectric. The energy targets discussed in the IAP fall into this category with "20% penetration by 2010" and "33% penetration by 2020". The energy definition is important because it is a measure of the amount of fossil fuel generation that can be displaced. However, in the analysis of intermittent generation the term penetration is often used to describe the ratio of the *nameplate capacity* of *intermittent* generation (wind and solar) divided by the *peak load* of the system. This is because the impact on operations is often a function of the intermittent renewable power output relative to the system load. Both definitions are important and both will be used within this report.

In 2006, the State of California had a peak load of 58,900 MW, of which 48,900 MW was within the California ISO operating area. There was 2,100 MW of wind and 330 MW of solar generation, yielding 4% intermittent generation penetration (as % of peak load) statewide and 5% penetration within California ISO.

Case 2010T represents a future scenario for the year 2010, with a total of 7,500 MW of wind and 1,900 MW of solar generation in California. In this scenario, the intermittent generation penetration is 15% statewide and 18% within the California ISO operating area. This scenario includes over 3,000 MW of new wind generation in the Tehachapi region, which is consistent with existing development plans. For this study, the Tehachapi region was broadly defined to include all wind generation in region 8 (for details see the AWS Truewind report, [7]).

Case 2020 represents a future scenario for year 2020 with 33% renewable energy, consistent with the California RPS goal. It includes 12,700 MW of wind and 6,000 MW of solar generation, yielding an intermittent penetration of 25% in California and 31% within California ISO.

Case 2010X represents an accelerated scenario where 33% renewable energy is integrated into a transmission system similar to what is anticipated for the year 2010. Although this scenario is not a realistic projection of renewable integration for year 2010, it provides valuable insights relative to the impact of intermittent generation. The 2020 scenario includes numerous system expansion assumptions to accommodate a projected peak load of 74,300 MW, including new transmission lines and conventional generating resources. The 2010X scenario, with a peak load of 62,600 MW, does not include those extensive generation and transmission additions. As such, grid performance of the 2010X scenario can be directly compared with scenarios 2010T and 2006. The primary differences between these scenarios are the levels of intermittent generation.

Similar comparisons with the 2020 scenario are more difficult to interpret, since differences are not limited to intermittent generation, but also include significant differences in conventional generation, load level, and transmission system infrastructure.

**Table 1. Renewable Generation Mix for Four Study Scenarios.**

| | Scenario | | | |
|---|---|---|---|---|
| | **2006** | **2010T** | **2010X** | **2020** |
| California Peak Load, MW | 58670 | 64336 | 64336 | 80742 |
| California Minimum Load, MW | 22804 | 25006 | 25006 | 31383 |
| California Load Factor, % | 60% | 60% | 60% | 60% |
| California ISO Peak Load, MW | 48466 | 53147 | 53147 | 66700 |
| California ISO Minimum Load, MW | 19066 | 20908 | 20908 | 26239 |
| California ISO Load Factor, % | 61% | 61% | 61% | 61% |
| Total Geothermal Capacity, MW | 2,400 | 4,100 | 3,700 | 5,100 |
| Total Biomass Capacity, MW | 760 | 1,200 | 1,000 | 2,000 |
| Total Solar Capacity, MW | 330 | 1,900 | 2,600 | 6,000 |
| Total Wind Capacity, MW | 2,100 | 7,500 | 12,500 | 12,700 |
| Wind Capacity in Tehachapi Region, MW | 760 | 4,200 | 5,800 | 5,800 |
| CA Wind+Solar Capacity Penetration, % | 4% | 15% | 23% | 23% |
| California ISO Wind+Solar Capacity Penetration,% | 5% | 17% | 26% | 25% |
| California ISO Wind+Solar Energy, GWH | 6201 | 26,111 | 43,255 | 49,933 |
| California Wind+Solar Energy, GWH | 6201 | 27,220 | 44,365 | 51,042 |
| CA Wind+Solar Energy Penetration, % | 2% | 8% | 13% | 12% |
| California ISO Wind+Solar Energy Penetration, % | 2% | 9% | 15% | 14% |

Notes: Load Factor = (Total Energy) / (Peak Load x 8760 hours)
Capacity Penetration = (Wind+Solar Capacity) / (Peak Load)
Energy Penetration = (Wind+Solar Energy) / (Peak Load x Load Factor x 8760 hours)

The wind and solar generation resources in this study are distributed among numerous sites across California. Table 2 summarizes the numbers of individual wind and solar sites represented in each scenario. For example, the 2010T scenario includes 12 concentrating solar facilities, 136 photovoltaic generation sites, and 98 wind generating plants, 40 of which are in the Tehachapi region. The 2020 scenario includes 43 concentrating solar facilities, 228 photovoltaic generation sites, and 147 wind generating plants. Detailed lists of individual wind generation and solar generation sites for each scenario are presented in Appendices A and B.

**Table 2. Wind and Solar Generation in California.**

| | Scenario | | | |
|---|---|---|---|---|
| | **2006** | **2010T** | **2010X** | **2020** |
| **Concentrating Solar (CS)** | | | | |
| Number of Sites | 7 | 12 | 42 | 43 |
| Total CS, MW | 330 | 1200 | 2100 | 3100 |
| **Photovoltaic (PV)** | | | | |
| Number of Sites | 0 * | 136 | 128 | 228 |
| Total PV, MW | 0 * | 630 | 530 | 2900 |
| **Wind Plants** | | | | |
| Total Sites in CA | 57 | 98 | 142 | 147 |
| Sites in Tehachapi Region | 16 | 40 | 54 | 54 |
| Total Wind, MW | 2100 | 7500 | 12500 | 12700 |

* Existing PV generation aggregated with load

Most of the historical grid operation data used in this study were supplied by the California ISO, and hence covered only the California ISO operating area. Operations data for other regions (Los Angeles Department of Water and Power [LADWP], Sacramento Municipal Utility District [SMUD], municipals, etc.) were not readily available to the study team. Hence, much of the statistical analysis focused on the impacts of intermittent generation on the operation of the California ISO operating area, rather than the entire state of California. As shown in Table 3 and Table 4, the vast majority of intermittent generation in the study scenarios is located within the California ISO operating area. For example, in scenario 2010T, 89% of solar and 96% of wind generation is within the California ISO operating area. In scenario 2010X, 88% of solar and 93% of wind generation are within California ISO. Given that the California ISO area has 83% of the total state load, California ISO has a higher proportion of wind and solar generation than the state as a whole. Therefore, it is reasonable for this study to focus on grid performance of the California ISO operating area. The statistical analysis looked at the impact of all of the wind and solar generation for each scenario compared to just the California ISO load. Although this was somewhat conservative in its approach, it was not too far from what is projected for California.

**Table 3. Locations of Wind and Solar Resources for Scenario 2010T.**

| | **Wind** | | **Solar** | | **Total Wind+Solar** | |
|---|---|---|---|---|---|---|
| | MW | % | MW | % | MW | % |
| California ISO | 7300 | 97% | 1700 | 89% | 9000 | 96% |
| Non-California ISO | 200 | 3% | 200 | 11% | 400 | 4% |
| Total California | 7500 | 100% | 1900 | 100% | 9400 | 100% |

**Table 4. Locations of Wind and Solar Resources for Scenario 2010X.**

| | **Wind** | | **Solar** | | **Total Wind+Solar** | |
|---|---|---|---|---|---|---|
| | MW | % | MW | % | MW | % |
| California ISO | 11600 | 93% | 2300 | 88% | 13900 | 92% |
| Non-California ISO | 900 | 7% | 300 | 12% | 1200 | 8% |
| Total California | 12500 | 100% | 2600 | 100% | 15100 | 100% |

## 2.2. Types of Analysis

The primary objective of this study was to identify and quantify system performance and any operational problems, including load following, regulation, operation during low-load periods, etc. Three primary analytical methods were used to meet this objective; statistical analysis, production simulation analysis, and quasi-steady-state analysis.

Statistical analysis was used to quantify variability due to system load, as well as wind and solar generation over multiple time frames (3 hour, hourly, 5-minute, 1-minute). The power grid already has significant variability due to periodic and random changes to system load. Wind and solar generation add to that variability, and increase what must be accommodated by load following and regulation with other generation resources. The statistical analysis quantified the grid variability due to load alone over several time scales, as well as the changes in grid variability due to wind and solar generation for each scenario. The statistical analysis also examined the changes in forecast accuracy for load alone versus load minus wind and solar generation.

Production simulation analysis with GE-MAPS™ was used to evaluate hour-by-hour grid operation of each scenario for 3 years with different wind and load profiles. The results quantified numerous impacts on grid operation including:

- Amount of maneuverable generation on-line during a given hour, including its available ramp-up and ramp-down capability to deal with grid variability due to load, wind and solar.
- Effects of load, wind and solar forecast alternatives
- Changes in dispatch of conventional generation resources due to the addition of new renewable generation
- Changes in emissions for oxides of sulfur ($SO_X$), oxides of nitrogen ($NO_X$) and carbon dioxide ($CO_2$) due to renewable generation
- Changes in costs and revenues associated with grid operation, and changes in net cost of energy
- Changes in transmission path loadings

Quasi-steady-state (QSS) simulation with PSLF was used to quantify grid performance trends and to investigate potential mitigation measures in the minute-to-minute time frame. QSS analysis involves minute-by-minute time-sequenced power flows for the entire WECC grid over several hours. These time simulations enabled examination of the impact of intermittent generation during challenging time periods, such as:

- Rapid morning load rise while wind generation is declining
- Operation during low load periods with minimal maneuverable generation on line
- Rapid evening load decrease while wind generation is increasing

The results from these three analytical methods complemented each other, and provided a basis for developing observations, conclusions, and recommendations with respect to the successful integration of wind and solar generation into the California power grid.

## 2.3. Data

A large amount of data was required for this study, and it was obtained through collaboration with many organizations. Details of the various items of data and their sources are explained below.

DPC provided power flow data, including the intermittent renewable generation mix and transmission system models for the 2006, 2010T, 2010X, and 2020 scenarios. A detailed discussion of how that data was developed is available in the report "*Intermittency Impacts of Wind and Solar Resources on Transmission Reliability*", by Davis Power Consultants [6].

California ISO provided historical load data for the years 2002, 2003, 2004, including hourly load MW (forecast and actual) and 4-second load MW for about 400 days. When applying this load data to the study scenarios, the data for all three years (2002-2004) was scaled up to the projected peak loads for each of the study years 2006, 2010, and 2020. In other words, each study year had three years of hourly load profiles, based on the historical load profile data for years 2002-2004.

California ISO also provided historical operations data for hydroelectric generation and Department of Water Resources (DWR) pump loads for years 2004 and 2006.

AWS Truewind provided historical wind data for years 2002, 2003, and 2004, including hourly wind MW (forecast and actual)·and 1-minute wind MW for 51 selected periods. A separate wind profile was provided for each wind farm included in the analysis.

Rumla Inc. compiled production simulation models and data for California and WECC from multiple sources, based on their extensive experience studying the California market.

Solar data was obtained from multiple sources, including:

- Hourly and 1-minute MW for Sungen and Luz for years 2002, 2003, 2004 (California ISO and UC-Davis)
- Hourly Stirling solar MW for Mojave and Imperial for 2002, 2003, 2004 (NREL and Stirling Energy Systems)
- Hourly and 15-minute photovoltaic MW for one year, aggregated by zip code (CPUC – Self Generation Incentive Program)
- 1-minute and 3-minute solar insolation data at two sites, for January and July 2002 (NREL and Atmospheric Research Science Center at SUNY-Albany)

Appendix C describes how the solar data was combined and processed to produce representative solar generation profiles future solar generation sites in California.

The load data, wind data and solar data used in this study were time-synchronized data sets. The load, wind and solar data for each hour (or minute) were derived from raw data corresponding to the same hour (or minute) of the same calendar year.

## 2.4. Terminology

The analysis of intermittency involves quantifying the variability inherent in the power system, as well as the ability of the system to accommodate that variability while maintaining performance within acceptable guidelines. In this study, variability is quantified by changes in operating point over several different time scales.

- 1-Hour Delta: This refers to the change from the previous hour, typically measured in MW. The ability of the operating area to accommodate hourly changes in load is called schedule flexibility in this study.
- 5-Minute Delta: This refers to the change from the previous 5-minute period, typically measured in MW. Load following and economic dispatch functions in California operate on a five-minute cycle.
- 1-Minute Delta: This refers to the change from the previous minute, typically measured in MW. Regulation functions operate in this time frame.

Throughout the following sections of this report, 1-hour delta is used as a measure of schedule flexibility, 5-minute delta is used as a measure of load following, and 1-minute delta is used as a measure of regulation.

Range and ramp capability are two terms used throughout this report to describe generation maneuverability. Both measure the response of the balance-of-portfolio (i.e., non-renewable) generators to the changing load, wind and solar conditions. They are defined as follows:

- Range: This refers to the remaining capacity (MW) available between the current operating point and either the maximum or minimum. Up range is the remaining MW capacity to the maximum, and down range is the MW capacity remaining to the minimum. Up and down range are a measure of schedule flexibility in response to hourly changes.
- Ramp rate capability: This refers to the speed (MW/minute) at which the system can use the remaining up and down range. Up ramp capability is the MW/min available to move up to the maximum, and down ramp capability is the MW/min available to move down to the minimum. Up and down ramp rate capability are a measure of load-following capability in response to 5-minute changes.

Both terms could be applied to individual generating units, but are most often used to describe system-wide generation maneuverability.

# 3.0 Statistical Analysis

The statistical analysis provides a broad view of the relative contribution of the intermittent renewables to system generation and overall system variability. All of the analyses presented in this section use the variable and uncertain behavior of system loads as the benchmark for examining the incremental changes in variability and uncertainty due to the intermittent renewables.

A fundamental characteristic addressed by power system operation and planning is the diurnal and seasonal variations in system load. It is axiomatic that system loads have daily peaks and valleys and that those extremes vary with season and between years. The installed generation must be capable of serving the load at all times. That requires that the generation have both sufficient rating and operational flexibility to meet the load.

In the following sections, various time frames and operating perspectives are evaluated. Throughout, the incremental impact of intermittent renewables is presented as a modification to the load. Thus, any load not supplied by the intermittent renewables is served by the rest of the available generation. This is referred to as the net load. Evaluations are based on the data described in Section 2.3 and the supporting appendices.

## 3.1. Temporal and Spatial Patterns

From a system-wide perspective, the load and intermittent renewable data exhibits a variety of temporal and spatial patterns. Such patterns include the daily, seasonal and yearly shifts in load and intermittent renewable generation. In addition, the spatial diversity of individual wind projects affects the system-wide wind generation pattern. These systemic characteristics are discussed in the following sections.

### *3.1.1. Daily and Seasonal Variations*

In this section, the overall impact of intermittent renewable generation on net load is examined. Figure 3 shows an average July day for 2003 with the load scaled to 2010 levels. The dark blue trace (left y-axis scale) is the total California ISO load. The shape is that of a typical summer diurnal pattern, including relatively high loads at mid-day and an evening load knuckle.

The green trace (right y-axis scale) shows the average power production of all California wind projects in the 2010T case (7,500 MW at 98 sites), also for July 2003. The wind power shows a typical summer diurnal pattern, with relatively lower generation mid-day, picking up in the afternoon. The orange trace (right y-axis scale) shows the average solar power production - again for all solar projects (PV and concentrating) in the 2010T case (2,200 MW). As expected, the solar production peaks at mid-day.

The light blue trace shows the total net load, i.e., load minus the wind and solar generation (abbreviated as L-W-S). This net load must be served by other generating resources. Note that the wind and solar tend to complement each other, with the result of largely maintaining the load alone shape at a reduced MW level.

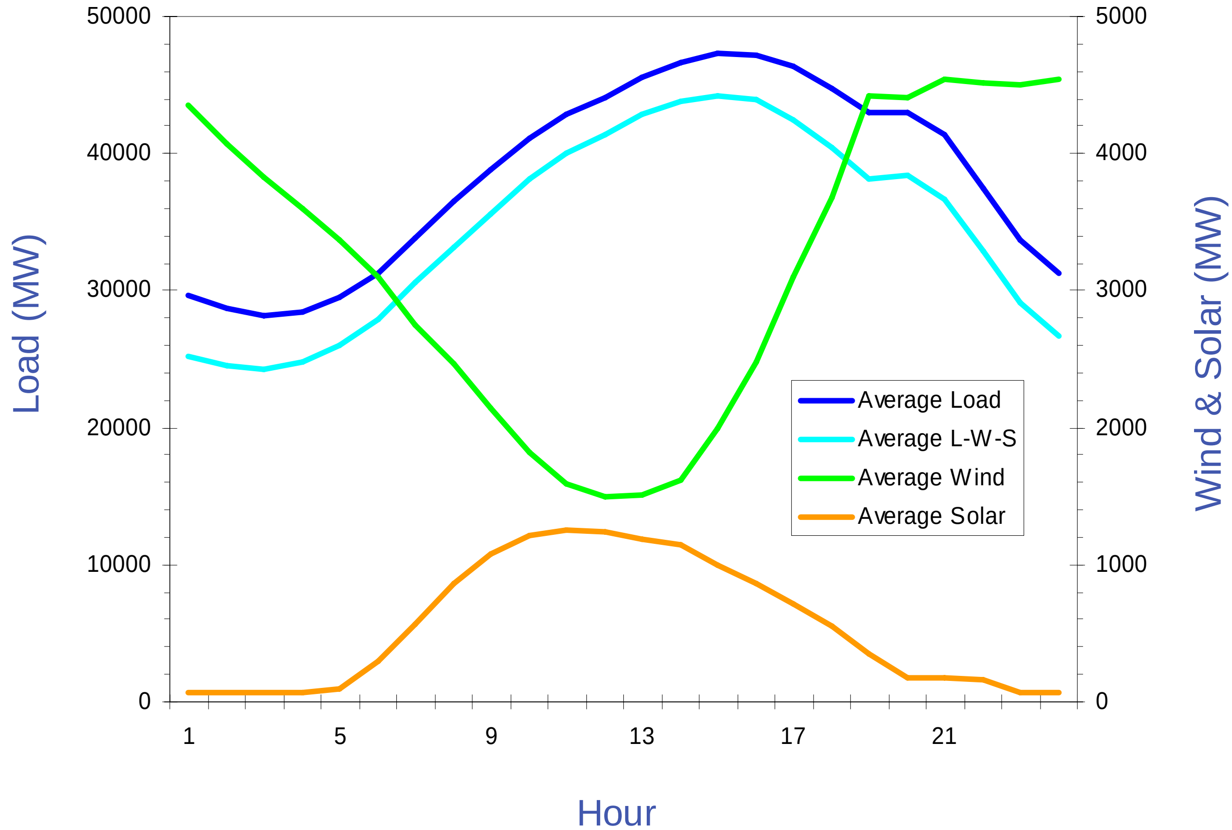


**Figure 3. Average System-wide Daily Load, Wind, Solar and Net Load Profiles of July 2003.**

The average behavior masks the day-to-day differences in total load and total intermittent generation production. Figure 4 shows the daily profiles of all days included in the averages shown in Figure 3. The general shape of the load profiles is similar, with the amplitude varying around the average peak by about +5,000 to -10,000 MW. The wind shapes also all have a diurnal pattern similar to the average with the amplitude varying around the average peak by about +2,000 to –2,000 MW. The solar variability is difficult to distinguish given the MW scale of Figure 4. Hence, Figure 5 shows only the solar temporal pattern of all days of July 2003. The general shape of the solar profiles is similar, with the amplitude the amplitude varying around the average peak by about +200 to -600 MW. The day-to-day solar variation is somewhat less than that of the wind.

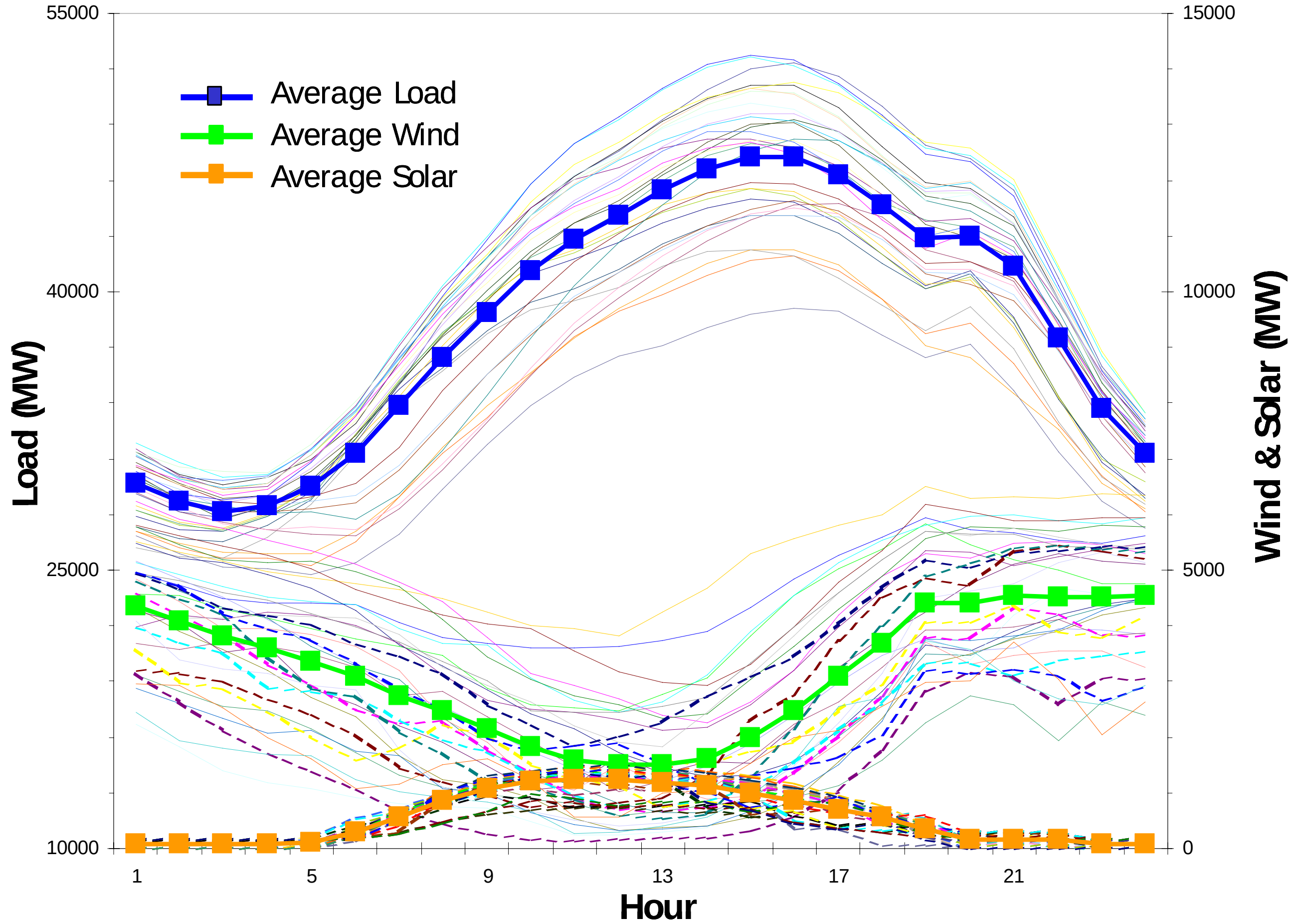


**Figure 4. All Systemwide Daily Load, Wind, and Solar Profiles for July 2003.**

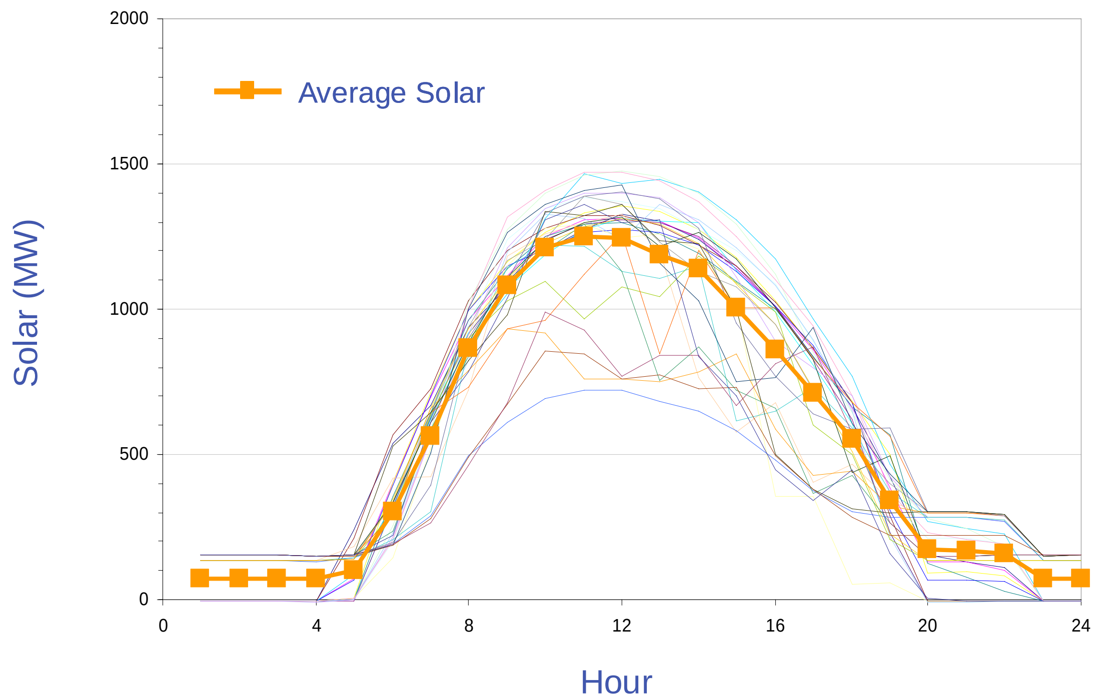


**Figure 5. All Systemwide Daily Solar Profiles for July 2003.**

The average load, wind, solar and net load profiles for January 2002 are shown in Figure 6. The daily peak load is significantly less than that observed in July, and the evening peak load may be the largest load of the day. Note that the average wind characteristic is flatter than in the summer, and is somewhat more coincident with the daily load shape.

All daily load, wind and solar profiles for January 2002 are shown in Figure 7 and Figure 8. Figure 7 shows daily profiles for the load and wind. The general shape of the load profiles is similar, with the amplitude varying around the average peak by about +3,000 to -3,000 MW. This range is less than that observed in July. The wind shapes also tend towards a diurnal pattern similar to the average, but with substantially greater day-to-day variability than observed in July.

Figure 8 shows the daily solar temporal pattern of all days in January 2002. The general shape of the solar profiles is similar, with the amplitude varying around the average peak by about +400 to -700 MW. As expected, the solar production is lower during January than July.

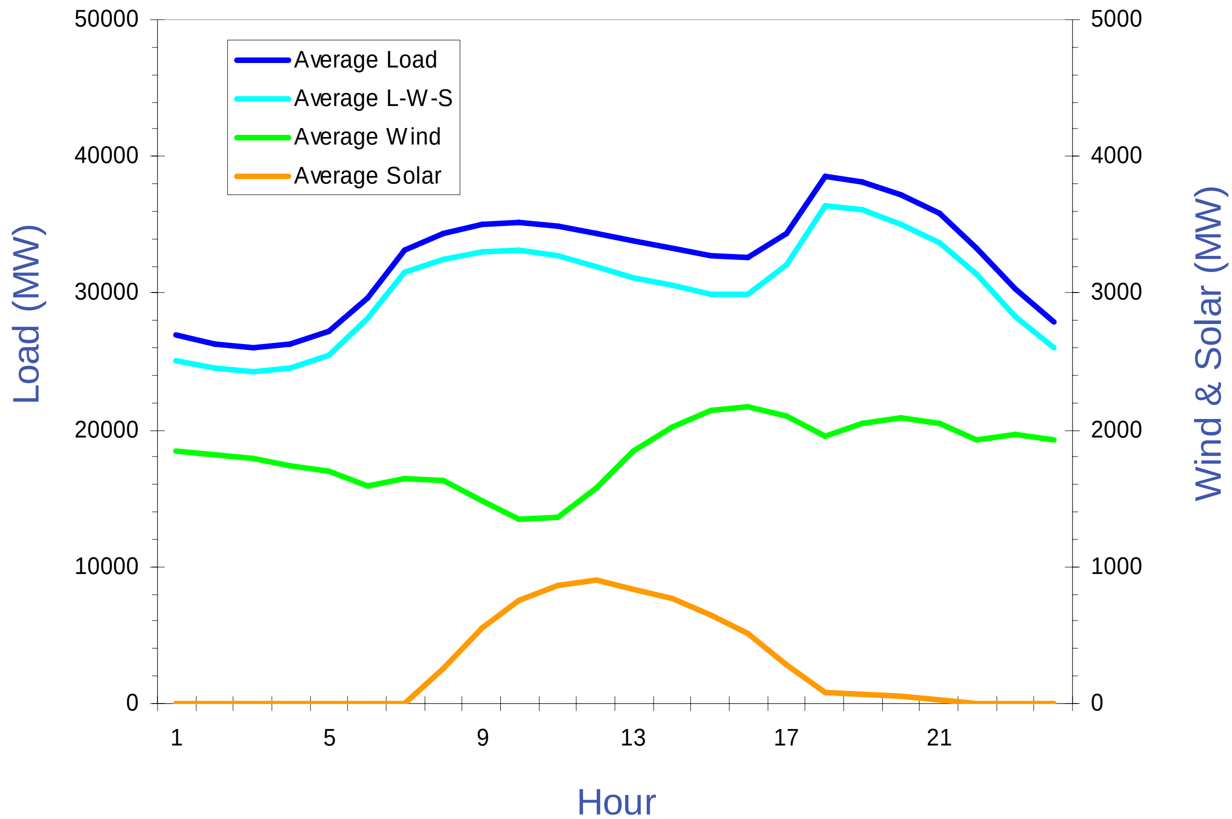


**Figure 6. Average Systemwide Daily Load, Wind, Solar, and Net Load Profiles of January 2002.**

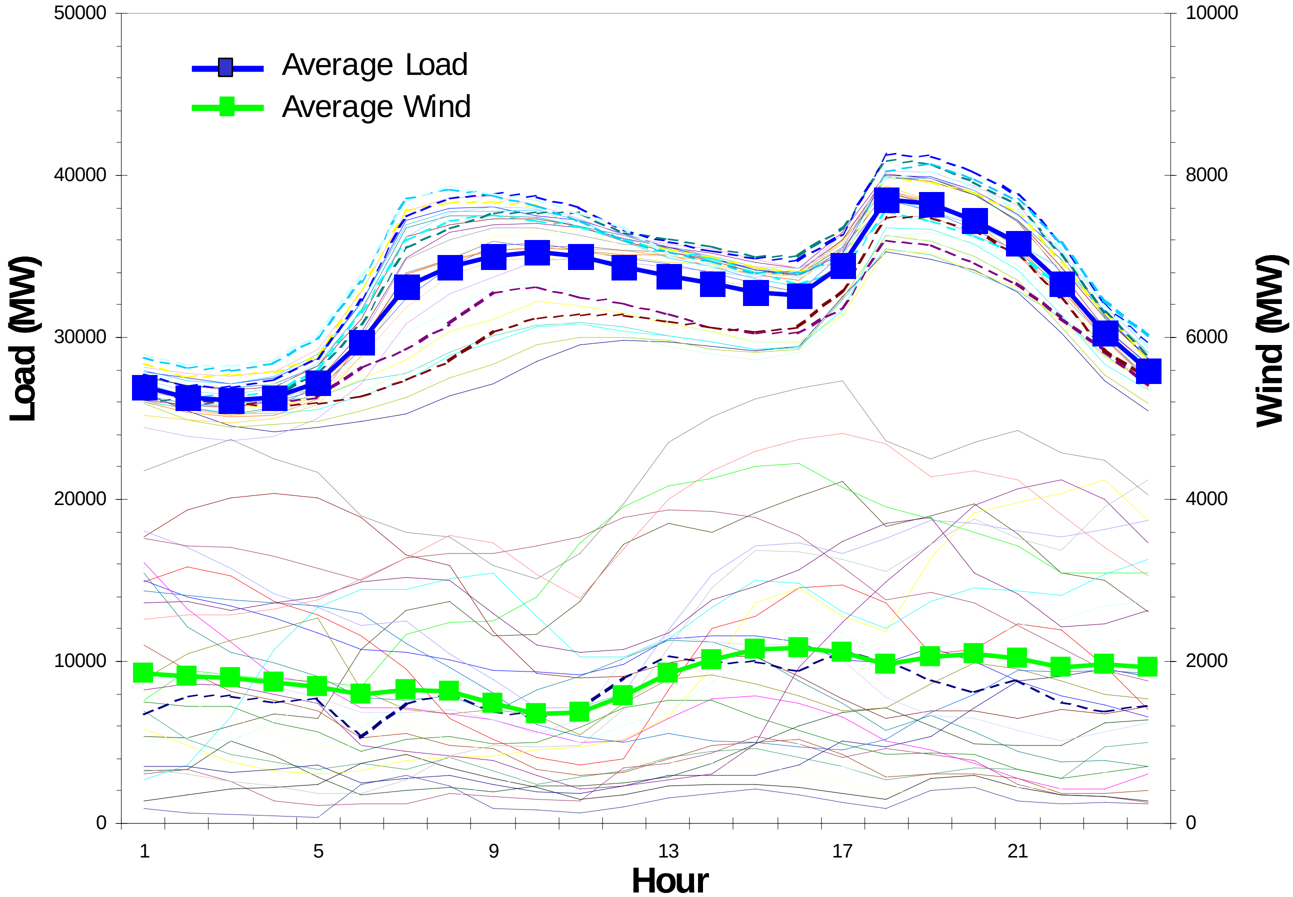


**Figure 7. All Systemwide Daily Load and Wind Profiles for January 2002.**

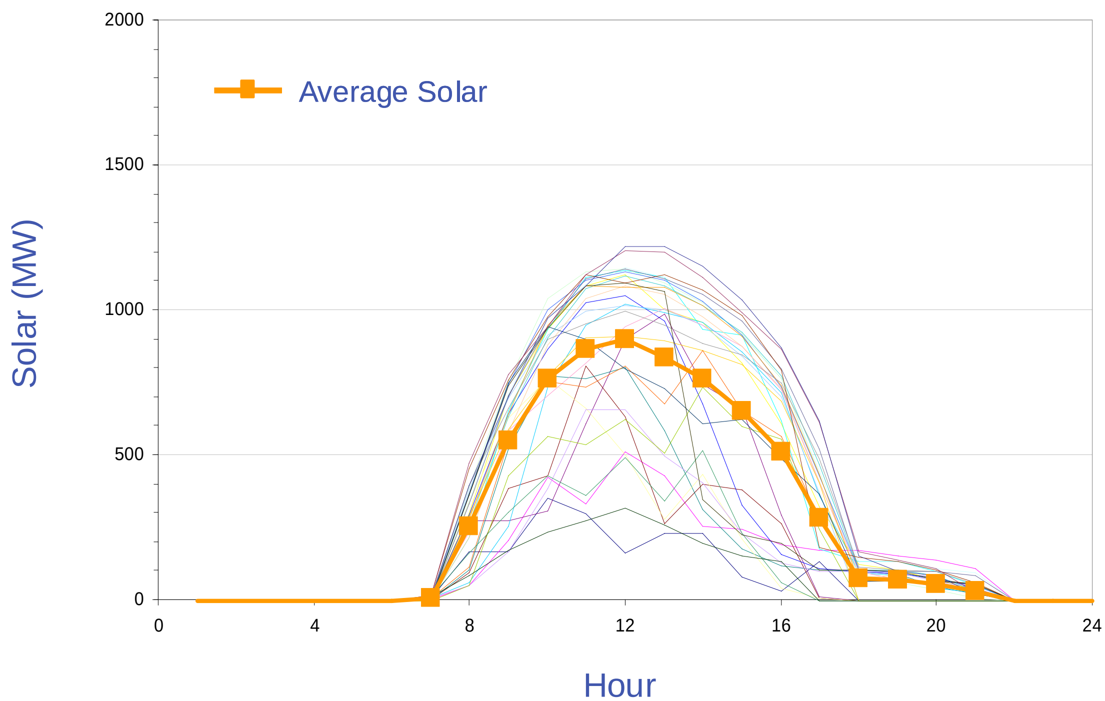


**Figure 8. All Systemwide Daily Solar Profiles for January 2002.**

### *3.1.2. Spatial Variations*

The power output of a single wind plant can occasionally change substantially in a relatively short period of time. For small systems, where a single plant constitutes a significant percentage of the total generation at a given point in time, this can create operational problems. In larger systems, where the output of multiple wind plants must be coincident to cause substantial impact on the bulk system, the spatial diversity of the plants becomes important.

Figure 9 shows the production of all wind plants in the 2010T scenario for a single day. The two heavy curves represent the total for all wind plants (blue) and the total for all wind plants in the Tehachapi region (green). The right y-axis scale applies for these totals. The left y-axis scale applies to the individual wind plants.

Figure 10 shows the individual production for only the wind plants in the Tehachapi region. A total of 40 plants in wind zone 8 are included in the Tehachapi region. Again, the right y-axis scale applies to the total, and the left y-axis scale applies to the individual wind plants.

Individual plants may exhibit substantial hour-to-hour changes in output. However, the plants are widely distributed around the state, which evens out the fast variability, leaving an overall diurnal pattern of production. This observation also holds for the Tehachapi region. The 4,200 MW of projects in the Tehachapi region is distributed over an area of approximately 500,000 acres , as discussed in the AWS Truewind report [7]. The total output of the individual plants in the Tehachapi region is not temporally coincident, and substantial benefits from spatial diversity are achieved.

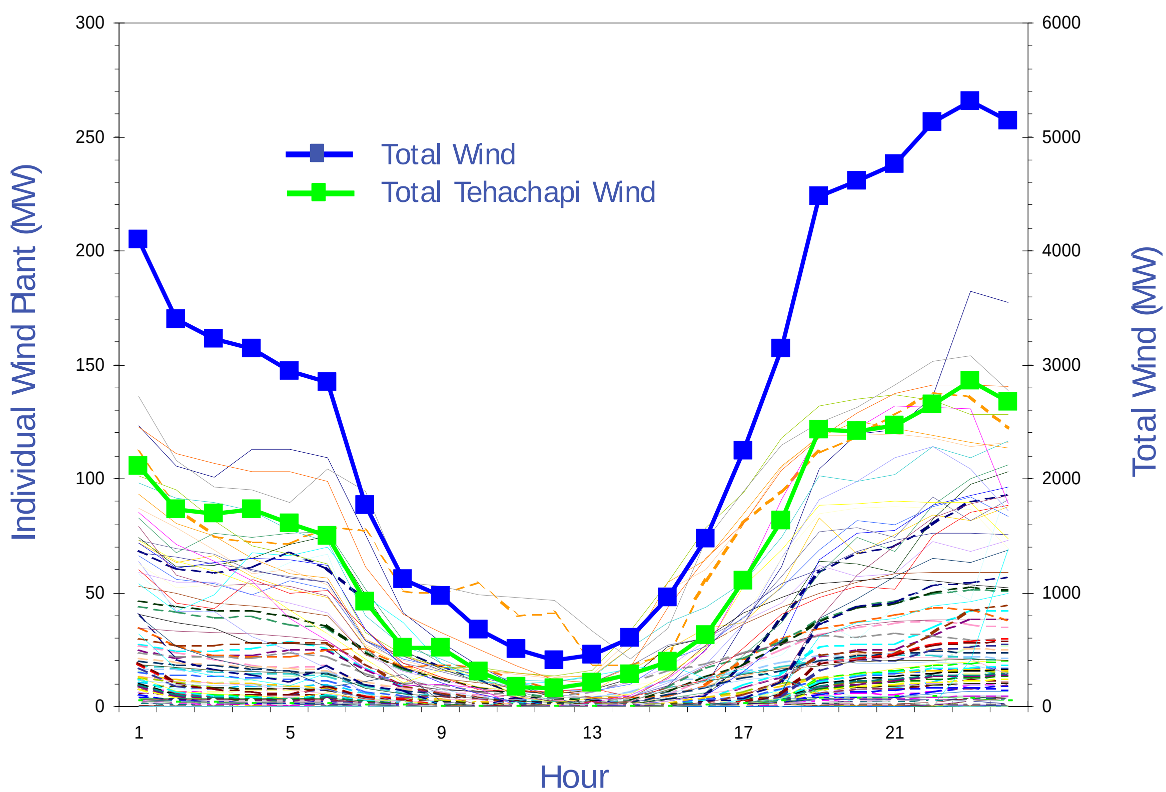


**Figure 9. All Individual California Wind Plant Profiles for July 21, 2003.**

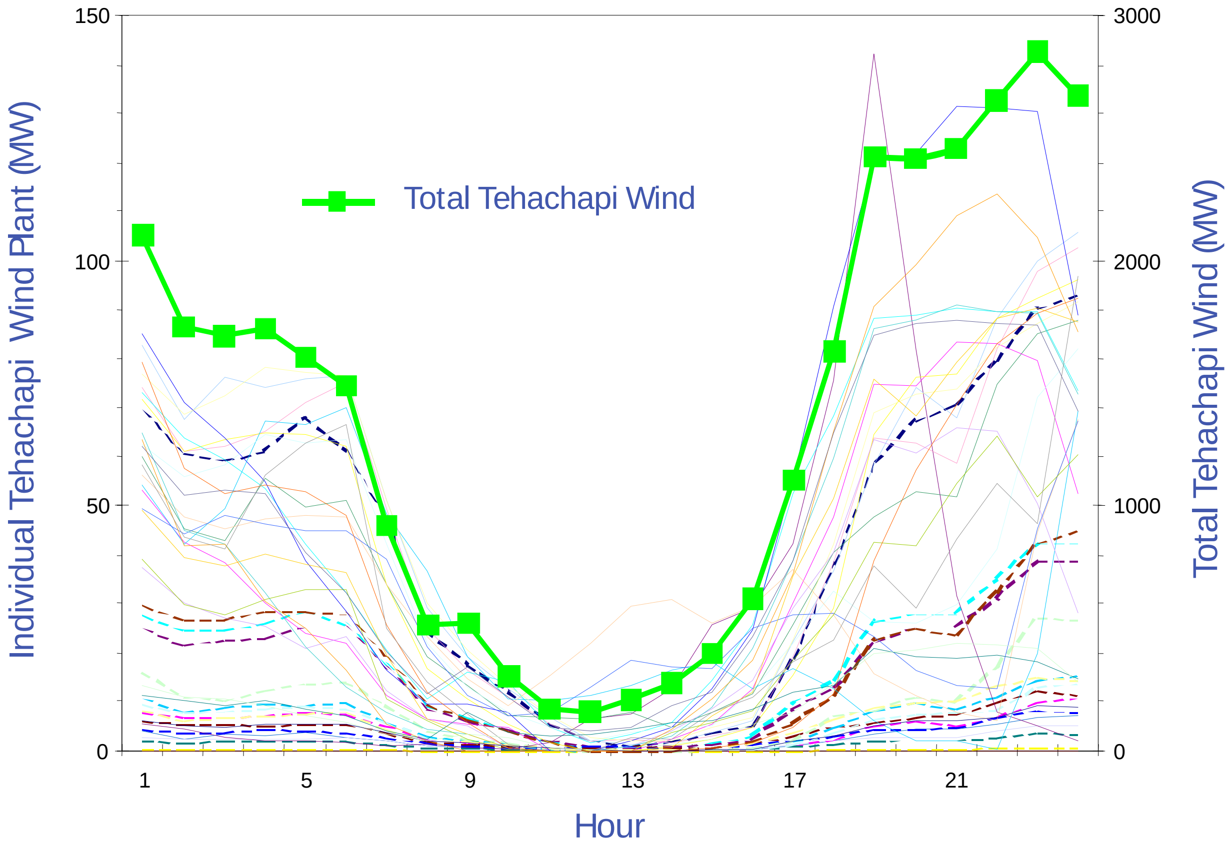


**Figure 10. All Individual Tehachapi Region Wind Plant Profiles for July 21, 2003.**

### *3.1.3. Yearly Variation and Penetration Relative to System Load*

System load patterns depend on weather, demographic, economic and other factors. System loads vary from year-to-year, beyond the overall trend of economically driven annual load growth. Production from intermittent renewable generation will also exhibit variation from year-to-year.

One way to look at annual production is with duration curves. Duration curves show all the hours (normally 8760) of a year, sorted from maximum to minimum. This provides a view of not only the maximum (extreme left) and minimum (extreme right), but also of the amplitude for all hours. Figure 11 shows three load, three wind and three solar duration curves for the 2010X scenario (12,500 MW of wind, 2,600 MW of solar). Each curve represents a different study year (2002, 2003, 2004), as defined by the load shape.

The load duration curves are the three upper traces in Figure 11. The left y-axis scale applies to these curves. The right y-axis scale applies to the wind and solar production curves. The wind production rarely (<1% of hours) exceeds 10,000 MW, and never quite drops to zero. As expected, the solar production is zero for about half the hours in the year. Note that the difference between the three load curves is greater than the differences between either the wind curves or the solar curves. This suggests that the year-to-year variability in overall energy production from the intermittent renewables is relatively lower than the year-to-year variability in overall load energy consumed.

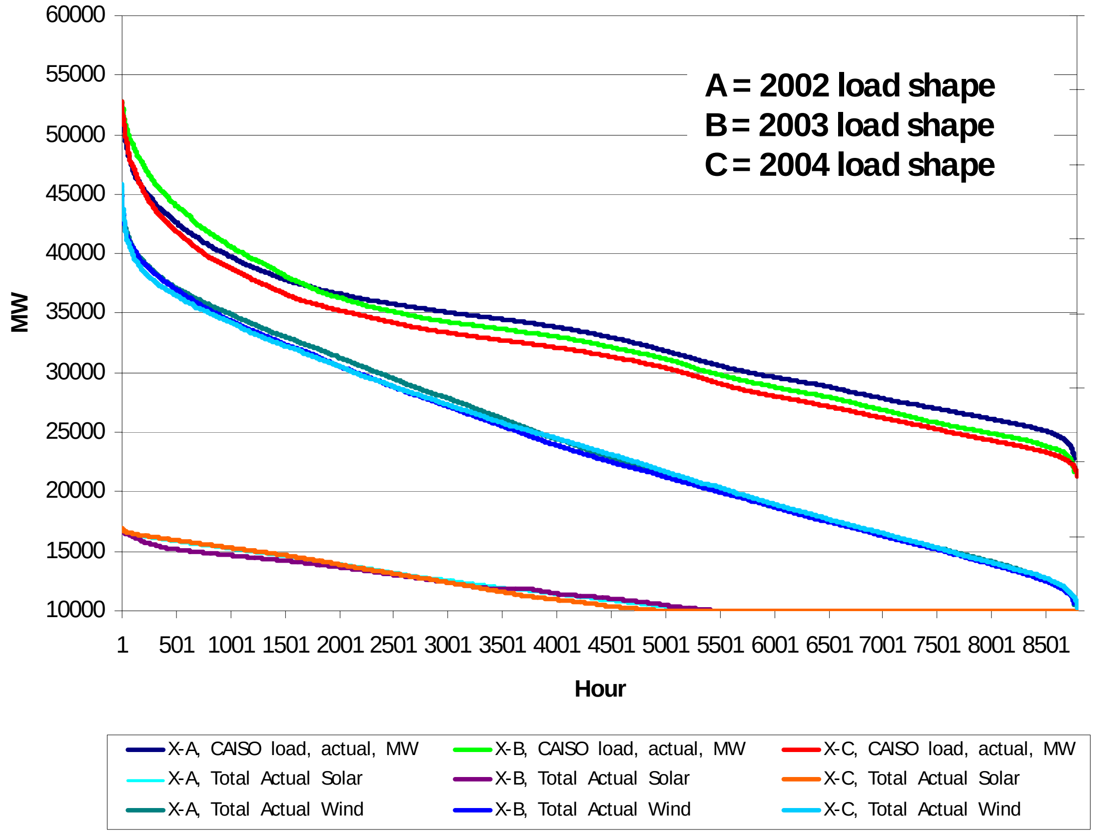


**Figure 11. Load, Wind, and Solar Duration Curves for 2010X Scenario.**

Figure 11 showed the individual duration curves for load, wind and solar over the three study years. As noted above, the balance of the system generation portfolio must serve any load not met by the intermittent renewables. Thus, the net load duration curves are more illuminating. Figure 12 shows three duration curves. The upper curve (blue) represents the total California ISO load, the middle curve (orange) represents the net load (L-W-S) for the 2010T scenario (7,500 MW of wind, 1,900 MW of solar), and the bottom curve (pink) represents the net load for the 2010X scenario (12,500 MW of wind, 2,600 MW of solar). For this set of curves, all three years of data are included, so the x-axis range is about 26,300 hours (3 years * 8760hours/year + 24 hours in a leap day).

The vertical grid lines divide the traces into ten equal parts – statistical bins of 1/10$^{th}$ or deciles of the total sample. These ten bins are used to parse the data in subsequent sections. The top 10 percent (peak) load hours are included in the left most bin, B#1. Similarly, the bottom 10 percent (light) load hours are included in the right most bin, B#10.

Several observations can be drawn from these curves. First, for most of the distribution (deciles 2 through 9) the 2010T net load is about 3,000 MW lower than the 2010T load alone case. Similarly, the 2010X net load is about 5000 MW less than the 2010 load alone case. Second, the intermittent renewables have a modest beneficial impact on the peak load, reducing it by 1,342 and 2,761 MW for the 2010T and 2010X cases, respectively. Finally, the intermittent renewables significantly reduce the minimum load. The horizontal line in Figure 12 highlights the fact that there are a significant number of hours for which the net load is less the minimum load alone.

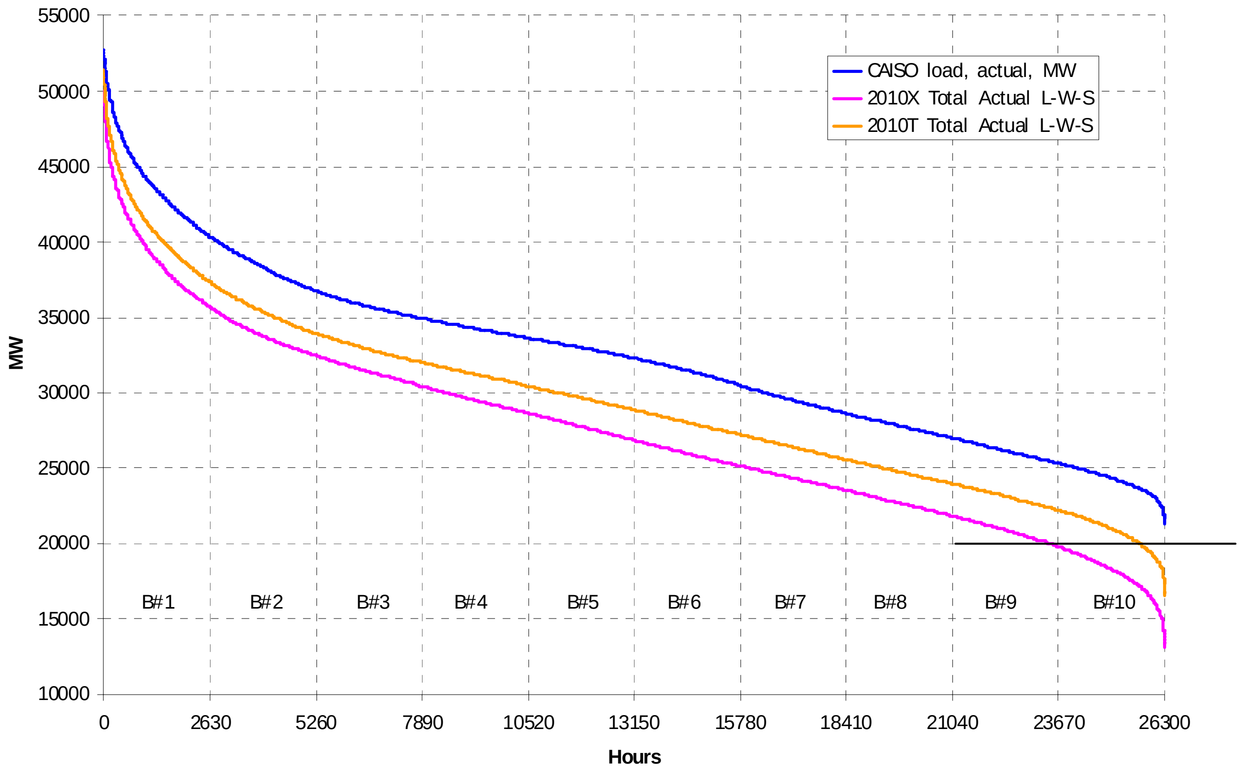


**Figure 12. 2010 Hourly Load and Net Load Duration Curves for 3 Years.**

The intermittent renewable impact on net load at light load conditions is show in further detail in Figure 13. This figure shows the load and net load duration curves for each of the three study years for the 2010X scenario, for the hours from 4,000 to 8,760. For all six duration curves, there is a sharp down turn in the last one hundred or so hours of each year. For the net load (L-W-S) curves, these hours correspond to coincident periods of low load and high wind. These extreme hours are likely to represent an operational challenge, and are explored further in subsequent sections of this report.

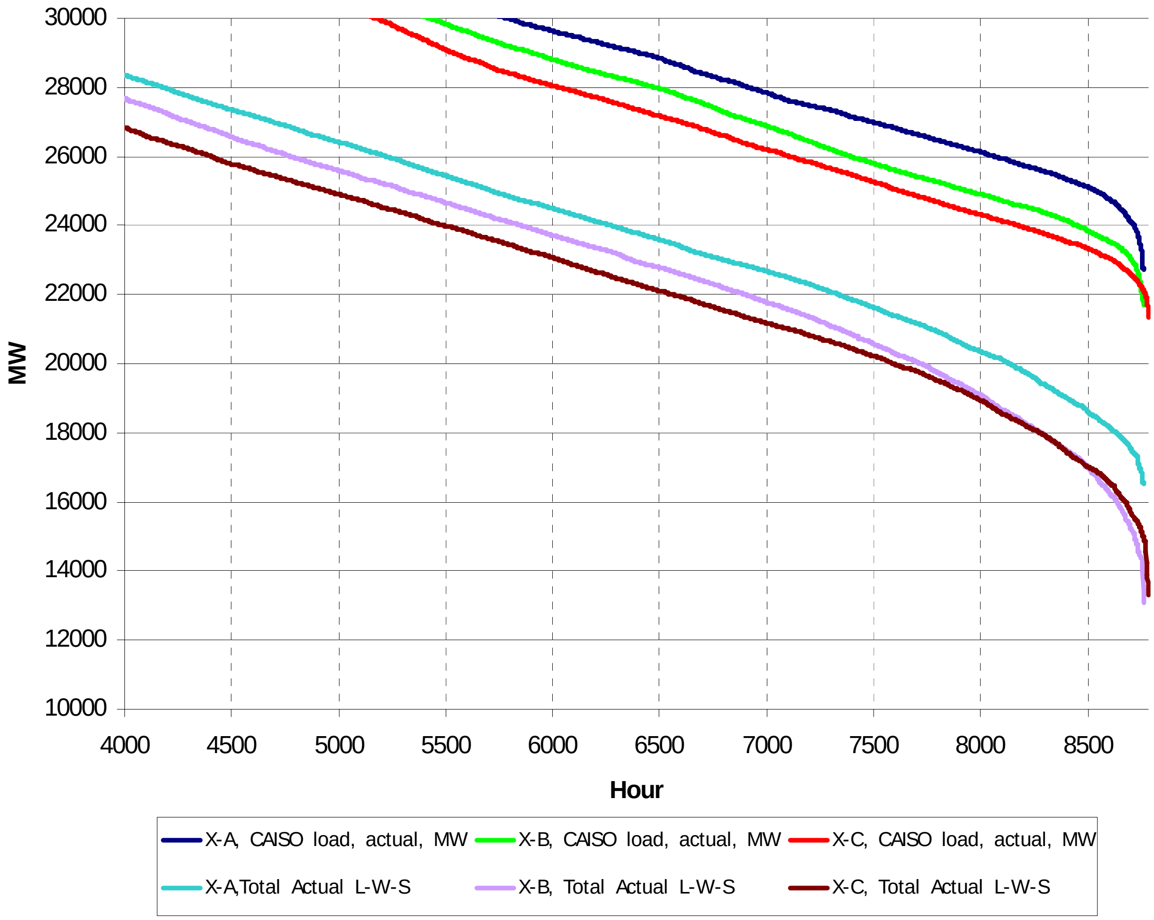


**Figure 13. Detail of Load and Net Load Duration Curves for 2010X Scenario.**

Overall, about 6% of hours in the 2010T case have a minimum net load below the load alone minimum, and about 20% of hours in the 2010X case have a minimum net load below the load alone minimum. Further, the absolute minimum is reduced by 4734MW and 8233MW for the 2010T and 2010X cases, respectively.

From a planning perspective, it is likely to be uneconomic to design the system to handle the absolute minimum net load. Rather, at some point it will be economic to modify the net load so as to set a floor on the minimum. The two duration curves of Figure 12 can be examined this way. For the expected 2010 renewables profile (scenario 2010T), the net load drops below 20,000 MW for 618 hours over the three years – about 2.4% of the time. This represents about ¾ of 1% of the total energy intermittent renewable energy. The 2010T net load drops below 18,000 MW for 35 hours over the three years.

For the extreme 2010X case, net load less than 20,000 MW occurs for 2,849 hours over the three years, accounting for 4.4% of the energy. For 2010X, net load less than 18,000 occurs 1,105 hours over three years, accounting for 1.2% of energy. However, Figure 13 shows that the minima vary significantly from year to year. These cases show broadly that a minimum generation level on the order of 18,000 to 20,000 MW will cover the vast majority of operation conditions in the 2010 time frame. Occasional drops below these levels may need to be handled by other means, which could include curtailment.  Results presented later for year 2020 reinforce this observation.

### *2006 and 2010 Penetration*

Renewable penetration is terminology used within the industry to describe the amount of renewable generation relative to the rest of the system. However, the term has no standard definition. From an operations perspective, the fraction of the total load being supplied at any given hour is a useful measure of penetration.  The impact on operations is generally lower at lower penetration, although other considerations are important as well.

Figure 14 shows wind production and penetration duration curves over the three study years for the 2010X scenario. As was apparent in Figure 11, the total wind production rarely exceeds 10,000 MW (<1% of the time) and never reaches the nominal maximum of 12,500 MW. For about 5% of hours, the wind penetration (wind MW/load MW for that specific hour) exceeds 30%, with only about 10 hours exceeding 40% in three years.

Figure 15 shows similar duration curves for the solar generation.  The solar penetration exceeds 5% about 5% of hours, and is less than 1% about half of all hours.

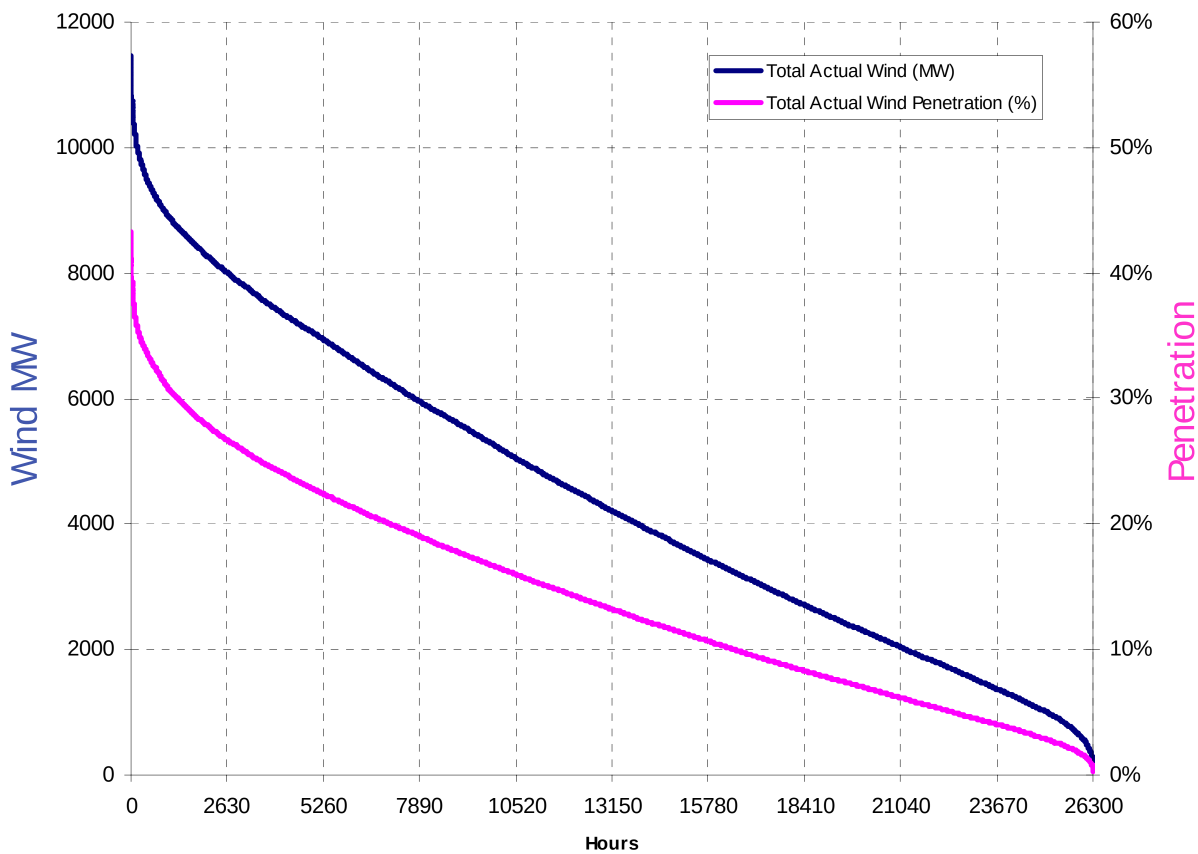


**Figure 14. 2010X Wind Production and Penetration Duration Curves.**

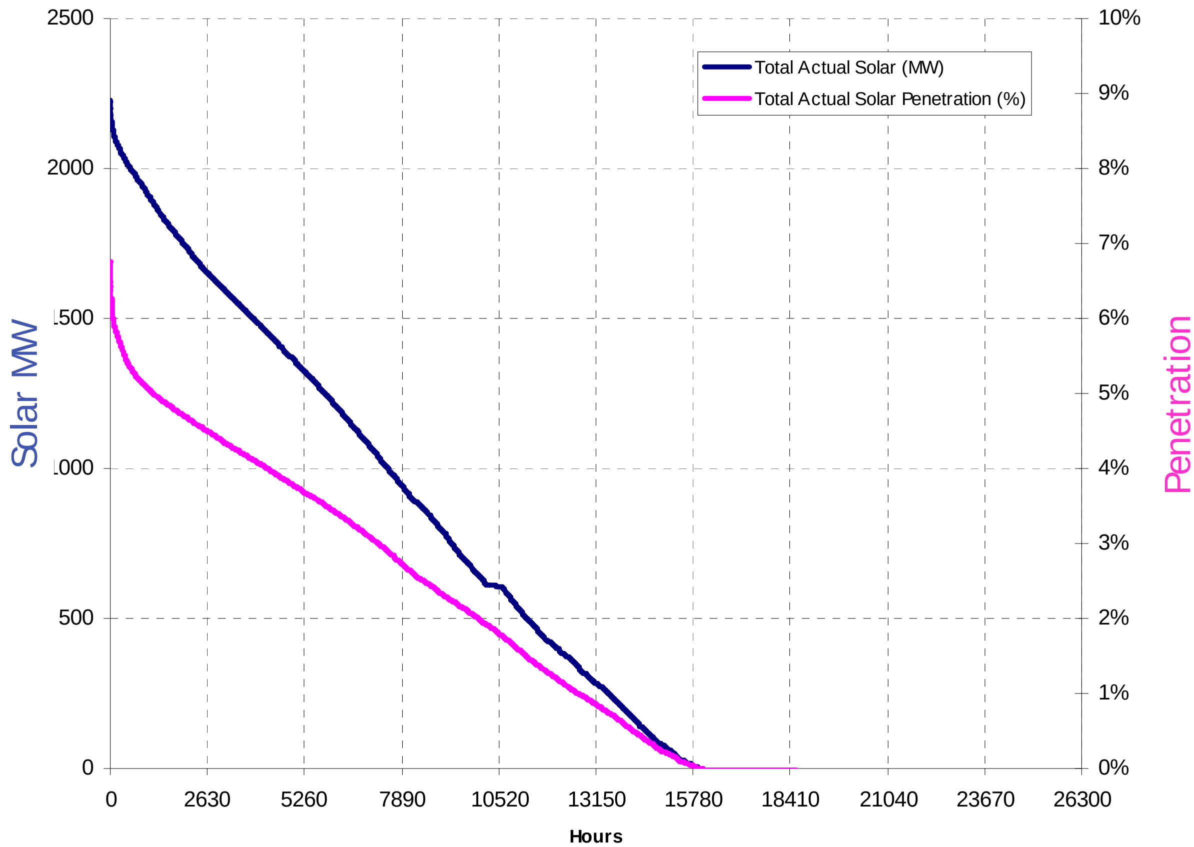


**Figure 15. 2010X Solar Production and Penetration Duration Curves.**

Another way to look at penetration is to consider it in the context of total system load levels. Figure 16 is the first of several graphs in which the results are grouped by the deciles described previously. For these graphs, the penetration figures are the average for each decile; i.e. the average wind production for all hours in that load decile divided by the average load of that decile. Three levels of wind generation are plotted, which correspond to the 2006, 2010T and 2010X scenarios.

Note that wind penetration tends to be higher at lighter load. This is consistent with Figure 3 and Figure 6 . As expected, wind penetration levels increase as wind resources are added to the system. The 2006 penetration of about 4% at light load increases to about 16% for the 2010T scenario, and to about 28% for the 2010X scenario

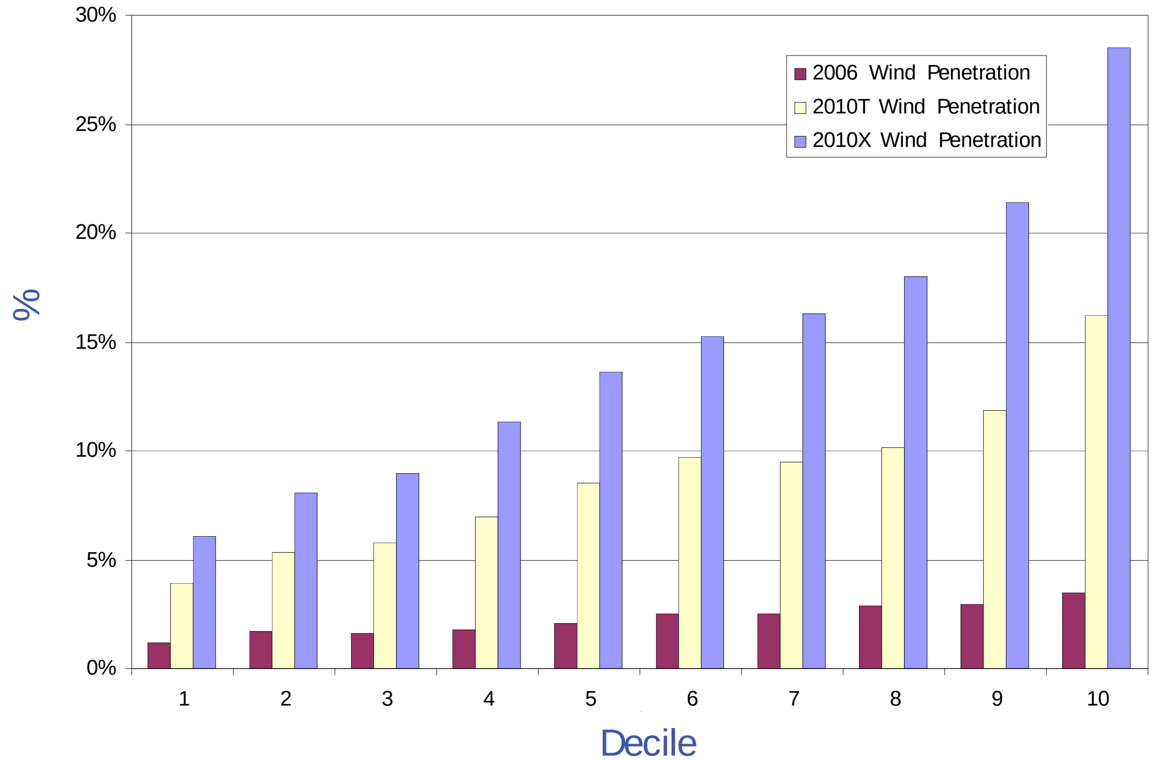


**Figure 16. 2006 and 2010 Hourly Average Wind Penetration by Decile.**

Average solar penetration by decile for the 2006, 2010T and 2010X scenarios is shown in Figure 17. Again, average penetration in a decile was calculated as average solar production for all hours in that load decile divided by the average load of that decile.

Note that solar penetration is positively correlated with system load, producing the most power during peak load periods. As expected, penetration levels increase as solar resources are added to the system. The 2006 penetration of about 0.6% at heavy load increases to about 2.1% for the 2010T scenario, and to about 3.2% for the 2010X illustrative scenario.

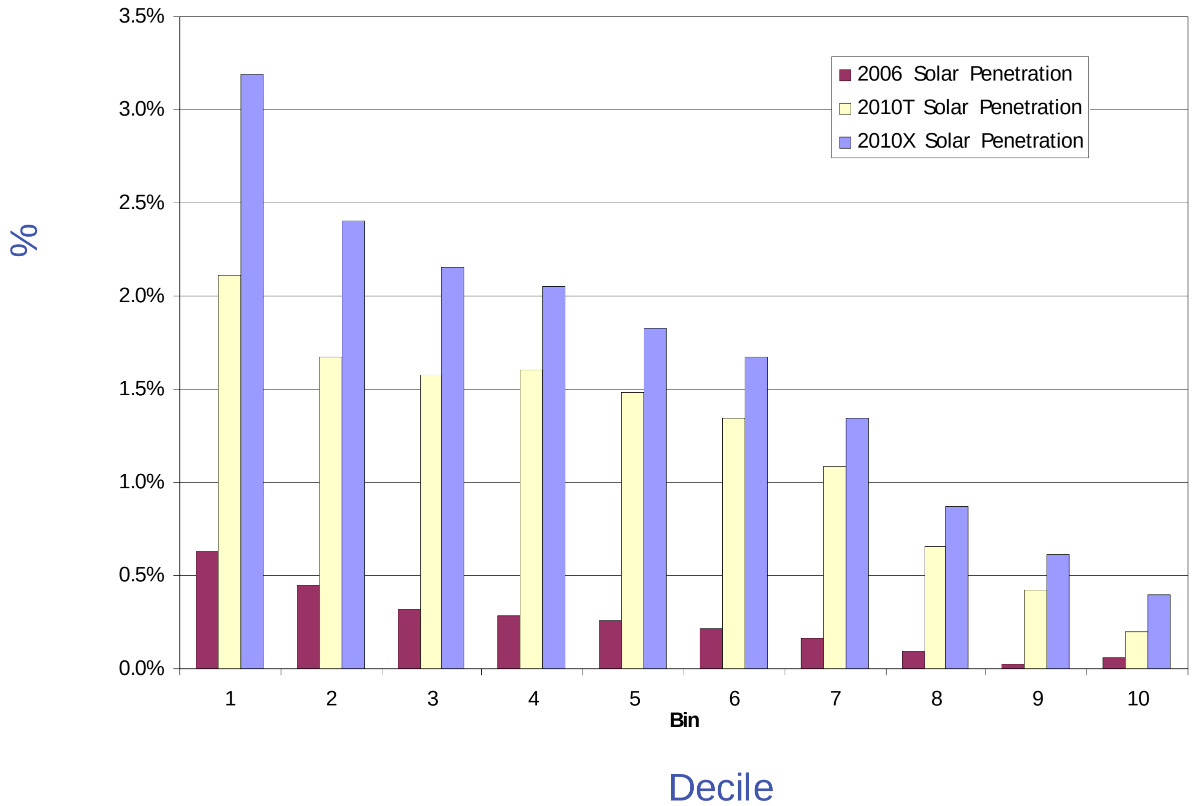


**Figure 17. 2006 and 2010 Hourly Average Solar Penetration by Decile.**

### *2020 Yearly Variation and Penetration*

Substantial load growth is expected between 2010 and 2020. In contrast, the increase in intermittent renewables between the 2010X and 2020 scenarios is relatively small. Figure 18 shows the load and net load duration curves for the three study years (2002, 2003, 2004) for the 2020 scenario. Compared to Figure 12 and Figure 13, the relative impact of the intermittent renewable is less. The minimum net load level of about 20,000 MW is significantly higher than that in the 2010 scenarios, and is only slightly less than the minimum load alone for 2010. This minimum net load reinforces the observations made earlier for the 2010 cases: a minimum net load capability of 20,000 MW will suit the requirements of the 2020 system.  In the event that renewables growth outpaces load growth in the years leading to 2020, a deeper minimum or temporary mitigation measures may be required.

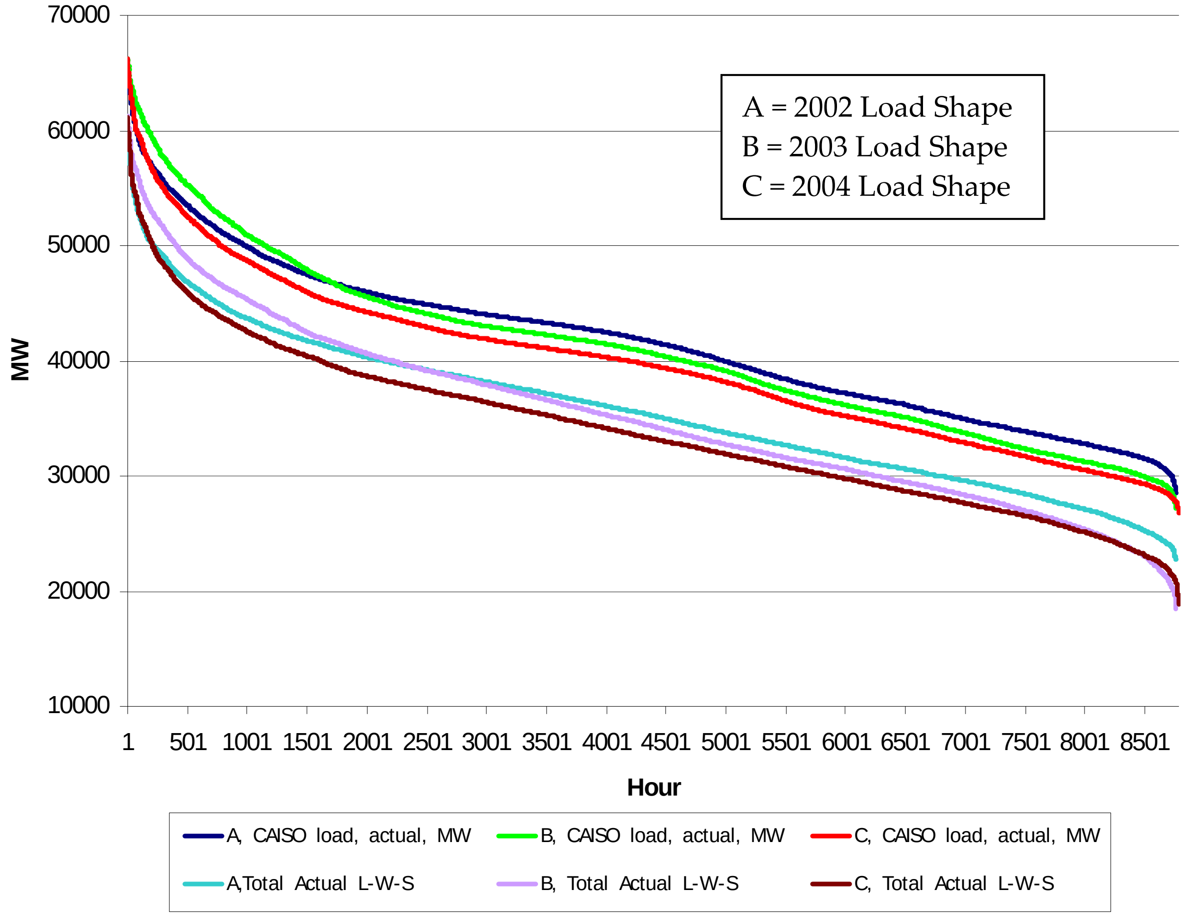


**Figure 18. 2020 Hourly Load and Net Load Duration Curves.**

Figure 19 shows the 2020 average wind and solar penetration by decile. Again, average penetration in a decile was calculated as average wind or solar production for all hours in that load decile divided by the average load of that decile. Wind penetration drops from the 2010X case, but solar penetration increases due to the substantial additions of solar from the 2010X scenario to the 2020 scenario.

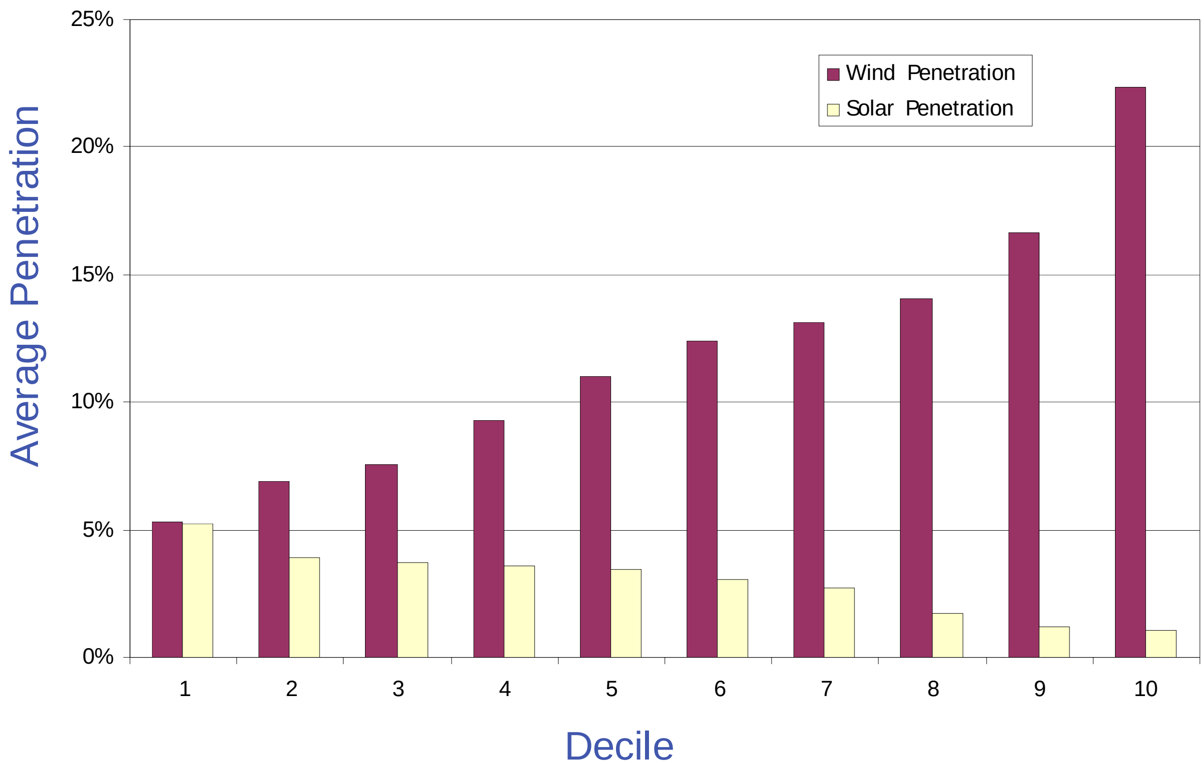


**Figure 19. 2020 Hourly Average Wind and Solar Penetration by Decile.**

## 3.2. Hourly Variability

The production of power from the intermittent resources varies continuously. This variability contributes to the variability that exists with loads. The power system must have the ability to not only satisfy the net load demand at any point in time, it must also have the flexibility to successfully move from condition to condition.

The changes in power that characterize load and intermittent renewables occur in a multitude of time frames. In order to quantify variability, these changes are analyzed statistically. Changes in load and net load (load minus wind minus solar) relate to three types of operating requirements: schedule flexibility, load-following and regulation. These groupings, while not entirely independent, allow for meaningful quantification of system behavior. Each of the three grouping are related to a specific time interval, over which the change (delta) is measured. Specifically:

- 1-hr Delta = Schedule flexibility
- 5-min Delta = Load Following capability/Economic Dispatch
- 1-min Delta = Regulation

Distribution of deltas across the data sets examined in this study tend to be normal distributions. Therefore, standard deviation ($\sigma$) of the distributions becomes a useful measure of variability. Higher $\sigma$ values correspond to higher variability. 3 times standard deviation ($\sigma$) is a proxy for maneuverability/flexibility requirements; the vast majority (99.7%) of events fall within +/-3σ (in a normal population). Increase in 3σ is one measure of requirement for additional maneuverability/flexibility due to increased variability

Figure 20 shows various profiles for an illustrative summer day. The solid curves show that day's hourly load, total load minus wind, and net load (load minus wind minus solar) profiles. These traces use the left y-axis scale. Like the average day of Figure 3, the combination of wind and solar production tend to reduce the overall net load. The curves with square symbols represent the 1-hour deltas for each of the three profiles. A 1-hour delta is defined as the change from one hour to the next. The right y-axis scale applies to the 1-hour deltas.

Note the rapid morning load rise from the 7$^{th}$ to 10$^{th}$ hours. This particular summer morning has relatively high rate of morning load rise, which reaches a maximum of about 3,600 MW/hr in the 7$^{th}$ hour (blue line with square symbol). During this same time period, the total wind power is declining, which increases the rate of net load rise. The maximum rate of rise, considering just load and wind, increases by about 600 MW/hr to 4,200 MW/hr (green line with square symbol). Also during this time period, solar generation is increasing. This tends to offset the decrease in wind. The net load (orange line, L-W-S) exhibits a maximum rate of load rise (orange line with square symbol) of about 4,000 MW/hr. This is an increase of about 400 MW/hr or about 10% over the load alone. In the afternoon, the decrease in system load and increase in wind generation reverses the situation. This results in a faster decline in the profiles (solid lines) and more negative 1-hour deltas (lines with square symbols). For this particular day, the fastest rate of load decline (about –4,200 MW/hr) occurs at the 22$^{nd}$ hour. The aggregate impact of the intermittent renewables in this time period is to reduce that rate of decline to about – 3,500 MW/hr. In general, faster rates of load rise and decline are more challenging for the system. Thus, the impact of intermittent renewables on the hour-to-hour changes in load is examined further.

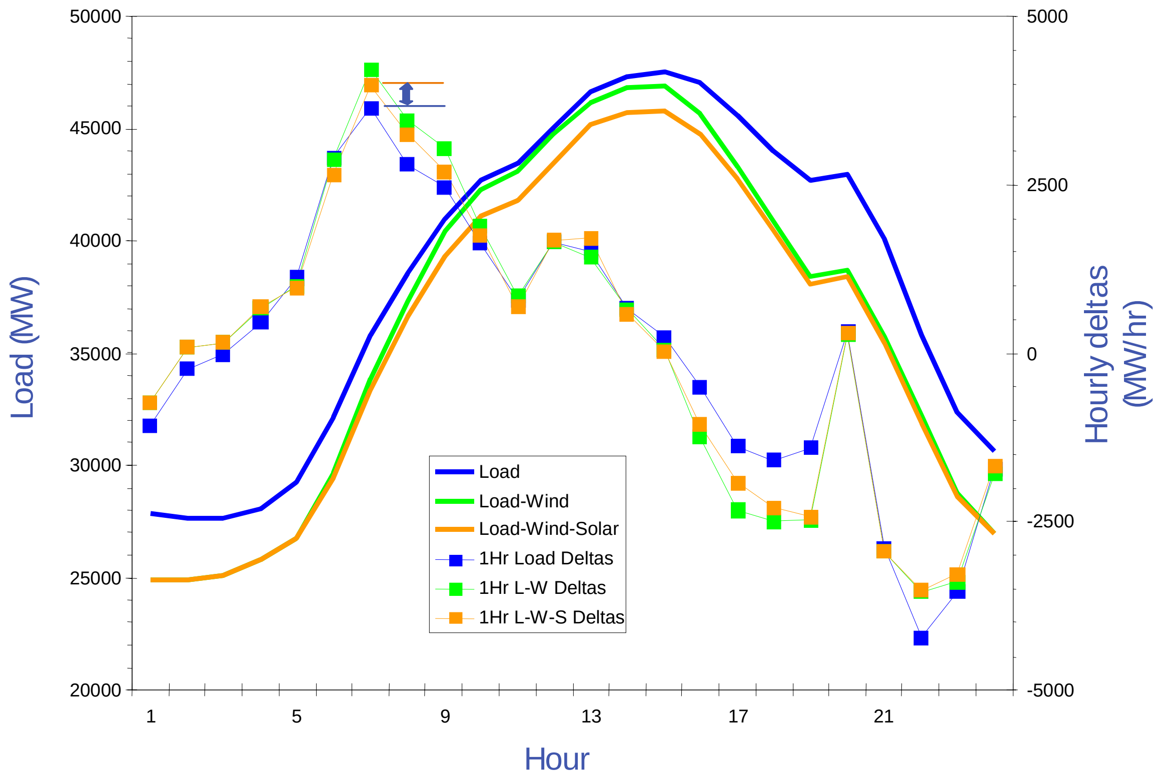


**Figure 20. Hourly Profiles and 1-Hour Deltas for an Example July 2002 Day.**

### *3.2.1. 2006 Variability Relative to Load Level*

Examination of the hour-to-hour variability of the system with and without wind and solar provides the most insight. Table 5 shows the 2006 hourly load statistical results, grouped into ten deciles on the basis of load alone. The 10 percent of peak load hours are included in decile 1, and the 10 percent of light load hours are included in decile 10. The table shows the maximum, minimum, and average load as well as the standard deviation (σ), maximum, minimum, and average 1-hour load deltas.

Table 6 shows the 2006 hourly net load, wind and solar statistical results, grouped into ten deciles on the basis of L-W-S. The first rows in the table show the maximum, minimum, and average net load (L-W-S). The next row shows the average load alone in each L-W-S decile. This average is different from the average load shown in Table 5 because deciles sorted by L-W-S are different from deciles sorted by load alone. The remaining rows show the standard deviation (σ), maximum, minimum, and average 1-hour net load deltas as well as the average wind production and penetration, and the average solar production and penetration.

All 2006 hourly variability figures cited in the remainder of the report are from these tables.

**Table 5. 2006 Hourly Load Statistics (MW).**

| | Load Decile | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Trait** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **All Year** |
| **Maximum** | 48113 | 36776 | 33503 | 31859 | 30655 | 29430 | 27776 | 26093 | 24615 | 23074 | 48113 |
| **Minimum** | 36779 | 33505 | 31860 | 30656 | 29430 | 27777 | 26093 | 24616 | 23074 | 19443 | 19443 |
| **Average** | 40163 | 34995 | 32598 | 31240 | 30063 | 28657 | 26911 | 25353 | 23840 | 22058 | 29587 |
| **σ Delta** | 1254 | 1555 | 1471 | 1363 | 1555 | 1816 | 1663 | 1436 | 1075 | 669 | 1436 |
| **Maximum Delta** | 4529 | 4854 | 4776 | 4375 | 6123 | 6071 | 3824 | 3245 | 2862 | 1706 | 6123 |
| **Minimum Delta** | -4334 | -4446 | -4382 | -4372 | -5122 | -4017 | -3535 | -3200 | -2868 | -2567 | -5122 |
| **Average Delta** | 225 | 317 | 209 | 130 | 117 | -19 | -178 | -262 | -309 | -229 | 0.2 |

**Table 6. 2006 Hourly Net Load and Intermittent Renewable Statistics (MW or %).**

| | Net Load Decile | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Net Load (L-W-S) Trait** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **All Year** |
| **Maximum** | 47736 | 35985 | 32800 | 31197 | 29994 | 28722 | 27068 | 25376 | 23849 | 22407 | 47736 |
| **Minimum** | 35988 | 32801 | 31197 | 29994 | 28722 | 27069 | 25377 | 23851 | 22407 | 18567 | 18567 |
| **Average** | 39398 | 34243 | 31938 | 30591 | 29386 | 27927 | 26188 | 24620 | 23136 | 21374 | 28880 |
| **Load Alone Average** | 40142 | 34971 | 32563 | 31228 | 30075 | 28681 | 26895 | 25349 | 23840 | 22133 | 29587 |
| **σ Delta** | 1294 | 1547 | 1456 | 1399 | 1587 | 1829 | 1700 | 1446 | 1049 | 699 | 1451 |
| **Maximum Delta** | 4924 | 4729 | 4857 | 4581 | 6091 | 5981 | 3947 | 3241 | 2914 | 2448 | 6091 |
| **Minimum Delta** | -4295 | -4533 | -4450 | -4592 | -5155 | -4174 | -3956 | -3452 | -2814 | -2613 | -5155 |
| **Average Delta** | 242 | 320 | 183 | 149 | 129 | -53 | -146 | -265 | -307 | -250 | 0.1 |
| **Wind Average** | 492 | 571 | 521 | 549 | 611 | 693 | 663 | 705 | 699 | 746 | 625 |
| **Wind Penetration** | 1.2% | 1.6% | 1.6% | 1.8% | 2.0% | 2.4% | 2.5% | 2.8% | 2.9% | 3.4% | 2.1% |
| **Solar Average** | 253 | 156 | 105 | 88 | 77 | 61 | 44 | 25 | 6 | 13 | 83 |
| **Solar Penetration** | 0.6% | 0.4% | 0.3% | 0.3% | 0.3% | 0.2% | 0.2% | 0.1% | 0.0% | 0.1% | 0.3% |

### *3.2.2. 2010 Variability*

Table 7 shows the 2010T hourly load statistical results, grouped into ten deciles on the basis of load alone. Table 8 shows the 2010T hourly net load, wind and solar statistical results, grouped into ten deciles on the basis of L-W-S. Table 9 shows the 2010X hourly net load, wind and solar statistical results, grouped into ten deciles on the basis of L-W-S. The format of these tables is the same as described above for Table 5 and Table 6.

All 2010 hourly variability figures cited in the remainder of the report are from these tables.

**Table 7. 2010 Hourly Load Statistics (MW).**

| | Load Decile | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Trait** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **All Year** |
| **Maximum** | 52761 | 40329 | 36738 | 34936 | 33616 | 32272 | 30459 | 28613 | 26993 | 25302 | 52761 |
| **Minimum** | 40331 | 36741 | 34937 | 33617 | 32272 | 30460 | 28613 | 26994 | 25302 | 21321 | 21321 |
| **Average** | 44042 | 38375 | 35747 | 34258 | 32966 | 31425 | 29510 | 27801 | 26143 | 24189 | 32445 |
| **σ Delta** | 1375 | 1706 | 1613 | 1495 | 1705 | 1992 | 1824 | 1575 | 1179 | 733 | 1575 |
| **Maximum Delta** | 4967 | 5323 | 5237 | 4797 | 6714 | 6657 | 4193 | 3559 | 3139 | 1871 | 6714 |
| **Minimum Delta** | -4753 | -4875 | -4806 | -4794 | -5617 | -4405 | -3877 | -3509 | -3145 | -2815 | -5617 |
| **Average Delta** | 247.0 | 347.9 | 229.5 | 142.4 | 128.6 | -22.1 | -195 | -287 | -339 | -251 | 0.2 |

**Table 8. 2010T Hourly Net Load and Intermittent Renewable Statistics (MW or %).**

| | Net Load Decile | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Net Load (L-W-S) Trait** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **All Year** |
| **Maximum** | 51418 | 37348 | 33909 | 31991 | 30432 | 28854 | 27211 | 25537 | 23953 | 22222 | 51418 |
| **Minimum** | 37349 | 33909 | 31991 | 30432 | 28856 | 27211 | 25538 | 23953 | 22224 | 16587 | 16587 |
| **Average** | 41210 | 35434 | 32889 | 31210 | 29655 | 28033 | 26378 | 24741 | 23102 | 20759 | 29341 |
| **Load Alone Average** | 41210 | 35434 | 32889 | 31210 | 29655 | 28032 | 26378 | 24741 | 23102 | 20758 | 29340 |
| **σ Delta** | 1541 | 1786 | 1670 | 1694 | 1818 | 1870 | 1747 | 1540 | 1211 | 933 | 1623 |
| **Maximum Delta** | 6234 | 5883 | 5725 | 6108 | 5144 | 6312 | 4852 | 4283 | 3464 | 2939 | 6312 |
| **Minimum Delta** | -4752 | -5236 | -4858 | -5283 | -5713 | -4507 | -4303 | -4100 | -3728 | -3427 | -5713 |
| **Average Delta** | 298 | 335 | 243 | 148 | 68 | -53.3 | -151 | -303 | -286 | -298 | 0.2 |
| **Wind Average** | 1707 | 2018 | 2060 | 2388 | 2811 | 3045 | 2800 | 2806 | 3120 | 4039 | 2680 |
| **Wind Penetration** | 4.1% | 5.7% | 6.3% | 7.7% | 9.5% | 10.9% | 10.6% | 11.3% | 13.5% | 19.5% | 9.1% |
| **Solar Average** | 927 | 638 | 560 | 549 | 489 | 424 | 319 | 182 | 111 | 50 | 425 |
| **Solar Penetration** | 2.2% | 1.8% | 1.7% | 1.8% | 1.6% | 1.5% | 1.2% | 0.7% | 0.5% | 0.2% | 1.4% |

**Table 9. 2010X Hourly Net Load and Intermittent Renewable Statistics (MW or %).**

| Net Load (L-W-S) Trait | Net Load Decile 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | All Year |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Maximum** | 50000 | 35686 | 32437 | 30415 | 28648 | 26841 | 25134 | 23518 | 21830 | 19795 | 50000 |
| **Minimum** | 35687 | 32438 | 30418 | 28648 | 26842 | 25135 | 23520 | 21831 | 19798 | 13088 | 13088 |
| **Average** | 39511 | 33841 | 31392 | 29516 | 27751 | 25961 | 24319 | 22682 | 20860 | 18020 | 27385 |
| **Load Alone Average** | 43549 | 37807 | 35330 | 34089 | 32827 | 31239 | 29540 | 27964 | 26753 | 25355 | 32445 |
| **σ Delta** | 1602 | 1792 | 1741 | 1859 | 1955 | 1911 | 1767 | 1591 | 1364 | 1081 | 1704 |
| **Maximum Delta** | 6672 | 6168 | 6607 | 6132 | 7219 | 6220 | 5541 | 4974 | 4384 | 3250 | 7219 |
| **Minimum Delta** | -4671 | -5690 | -5224 | -5543 | -5986 | -5046 | -4769 | -4649 | -4422 | -4141 | -5986 |
| **Average Delta** | 327.8 | 328.0 | 215.6 | 175.2 | 89.0 | -72.4 | -138.9 | -296.9 | -290.2 | -335.8 | 0.1 |
| **Wind Average** | 2649 | 3055 | 3177 | 3875 | 4476 | 4756 | 4824 | 5039 | 5729 | 7230 | 4481 |
| **Wind Penetration** | 6.1% | 8.1% | 9.0% | 11.4% | 13.6% | 15.2% | 16.3% | 18.0% | 21.4% | 28.5% | 14% |
| **Solar Average** | 1389 | 910 | 761 | 698 | 600 | 521 | 397 | 243 | 163 | 100 | 578 |
| **Solar Penetration** | 3.2% | 2.4% | 2.2% | 2.0% | 1.8% | 1.7% | 1.3% | 0.9% | 0.6% | 0.4% | 1.8% |

### *Relative to Load Level*

Figure 21 shows an "open-high-low-close" stock chart for the extreme intermittent renewables 2010X case hourly load deltas (red) and hourly net load deltas (yellow) by decile. The top of a bar represents the average value of hourly delta plus the standard deviation. The bottom of a bar represents the average value of hourly delta minus the standard deviation. The top of a vertical line represents the maximum hourly deltas, and the bottom of a vertical line represents the minimum hourly delta.

The chart shows that wind and solar have the most impact on hourly variation, including extremes, under light load conditions. The standard deviation of the load alone variability for the 10th decile is 733 MW, increasing by 348 MW to 1081 MW with wind and solar. This means that within that light load decile, there is a 99.7% expectation (3σ) that hour-to-hour changes will be less than ±2199 MW without wind and solar. The 3σ expectation with wind and solar is for the hourly changes less than ±3240 MW. Under these light load conditions, the largest load alone increase is 1871 MW and the largest net load increase is 3250 MW. Thus, the maximum load alone increase is less than the 3σ expectation, and the maximum net load increase is slightly more than the 3σ expectation. The largest load alone decrease is -2815 MW and the largest net load decrease is -4141 MW. Both the load alone and net load decreases are more than the 3σ expectation under light load.

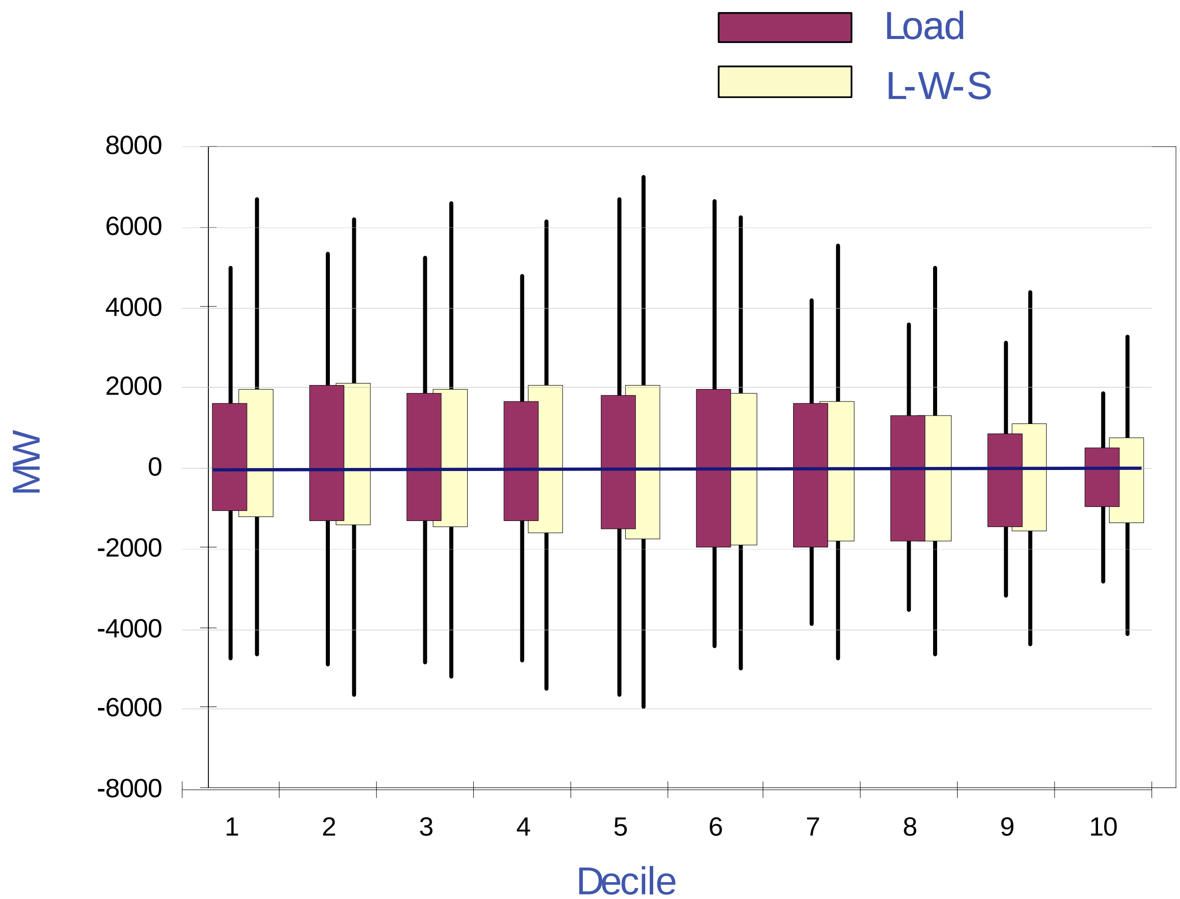


**Figure 21. 2010X Hourly Load and Net Load Delta Stock Chart by Decile.**

Figure 22 shows the standard deviation of load and net load hourly deltas for the 2006, 2010T and 2010X scenarios. Left to right, the five bars in each decile represent the standard deviations of 2006 load delta, 2006 net load delta, 2010 load delta, 2010T net load delta and 2010X net load delta. The chart shows that wind and solar in both 2006 and 2010 scenario have the most impact on hourly variation, including extremes, under light load conditions.

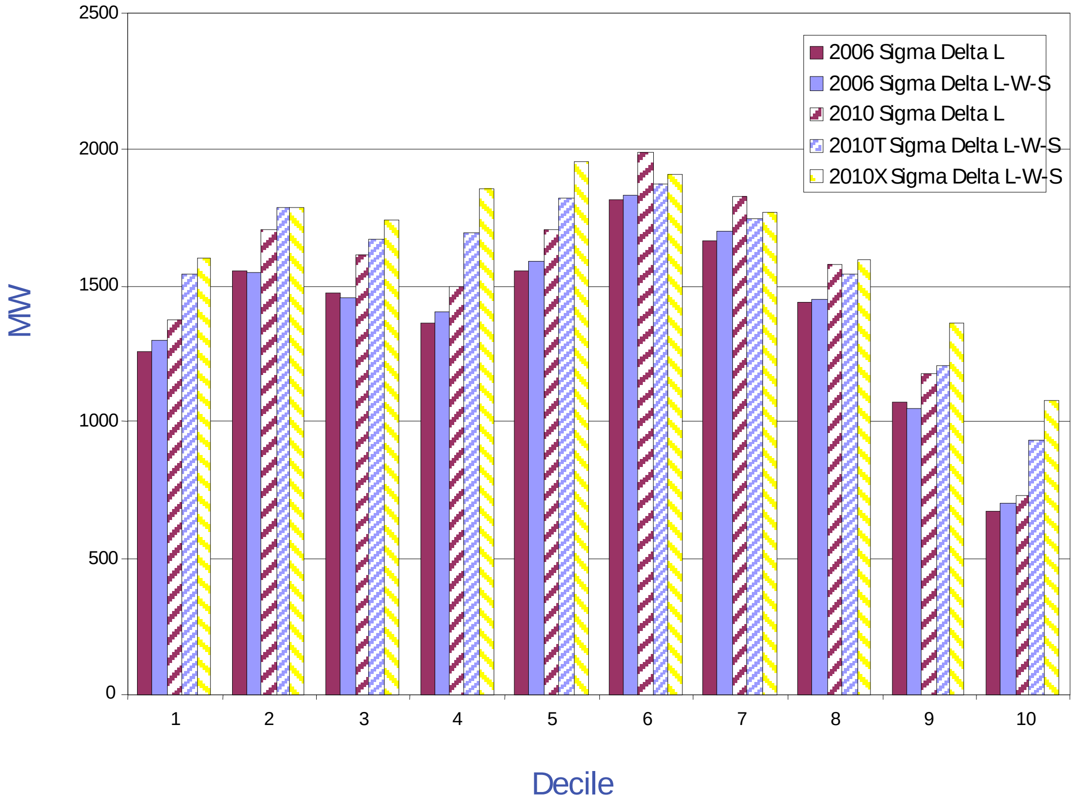


**Figure 22. 2006 and 2010 Standard Deviation of Hourly Load and Net Load Deltas.**

### *Relative to Time-of-Day*

Figure 23 shows the average hourly wind and solar penetration for every hour of the day for the extreme 2010X scenario. The wind and solar penetration is defined as average production divided by average load at the specified hour for an entire year. Wind penetration dips down to about 8 percent in the morning, and rises back up to about 21 percent at midnight. Solar penetration reaches its peak of 4 percent at mid-day.

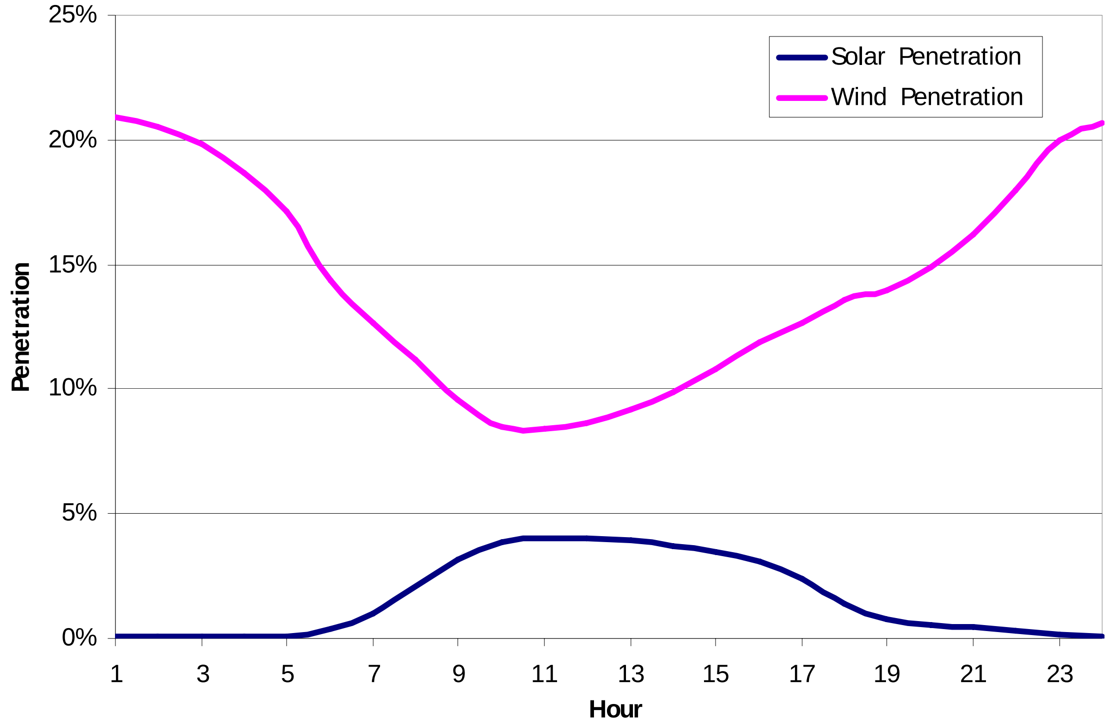


**Figure 23. 2010X Average Hourly Wind and Solar Penetration by Hour of Day.**

Periods of peak demand and rapid rise in load are given special attention by system operators. The summer morning load rise, especially during periods of sustained hot weather, presents one of the more severe tests for the system.

The "open-high-low-close" stock charts of Figure 24 through Figure 26 were developed to identify the impact of wind and solar over the course of a summer or winter day, respectively. These figures show the 2010X hourly load deltas (red) and hourly net load deltas (yellow) by time of day. As described previously, the top of a bar represents the average value of hourly delta plus the standard deviation. The bottom of a bar represents the average value of hourly delta minus the standard deviation. The top of a vertical line represents the maximum hourly deltas, and the bottom of a vertical line represents the minimum hourly delta.

Figure 24 shows hourly deltas for the 2010X load and net load scenarios based on the three years of 2002, 2003 and 2004. The maximum overall hourly load delta is about 6,500 MW/hr, at 7 am. The maximum overall hourly net load delta is about 7,000 MW/hr, also at 7 am. The largest increase in maximum hourly delta, between the load and net load cases, is about 2,000 MW/hr at 5pm. The minimum overall hourly load delta is about –5,500 MW/hr, at 10 pm. The minimum overall hourly net load deltas is about –6,000 MW/hr, also at 10 pm. The largest increase in minimum hourly delta, between the load and net load cases, is about 1,500 MW/hr at 6 pm.

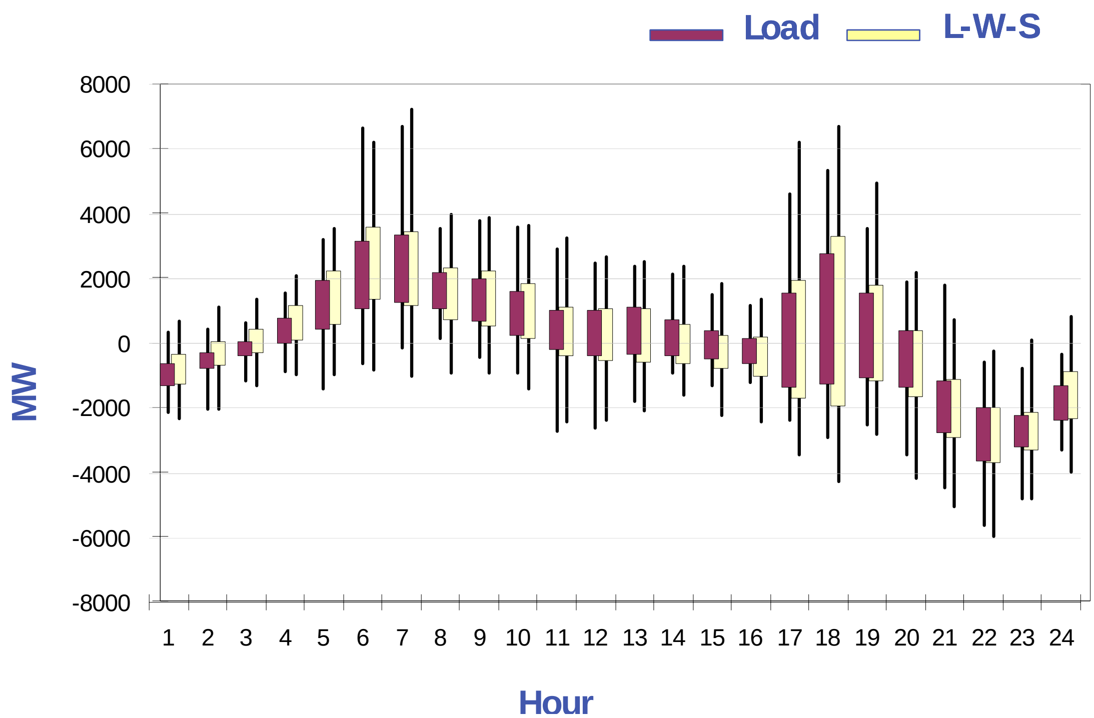


**Figure 24. 2010X Hourly Load and Net Load Delta Stock Chart by Hour of Day.**

Figure 25 is based on all July days in the three study years of 2002, 2003, and 2004 for the 2010X scenario. During July mornings, the net load rises 500 MW/hr to 1000 MW/hr faster than load alone. The afternoon and evening swing in net load is also more pronounced at 6 pm than with load alone.

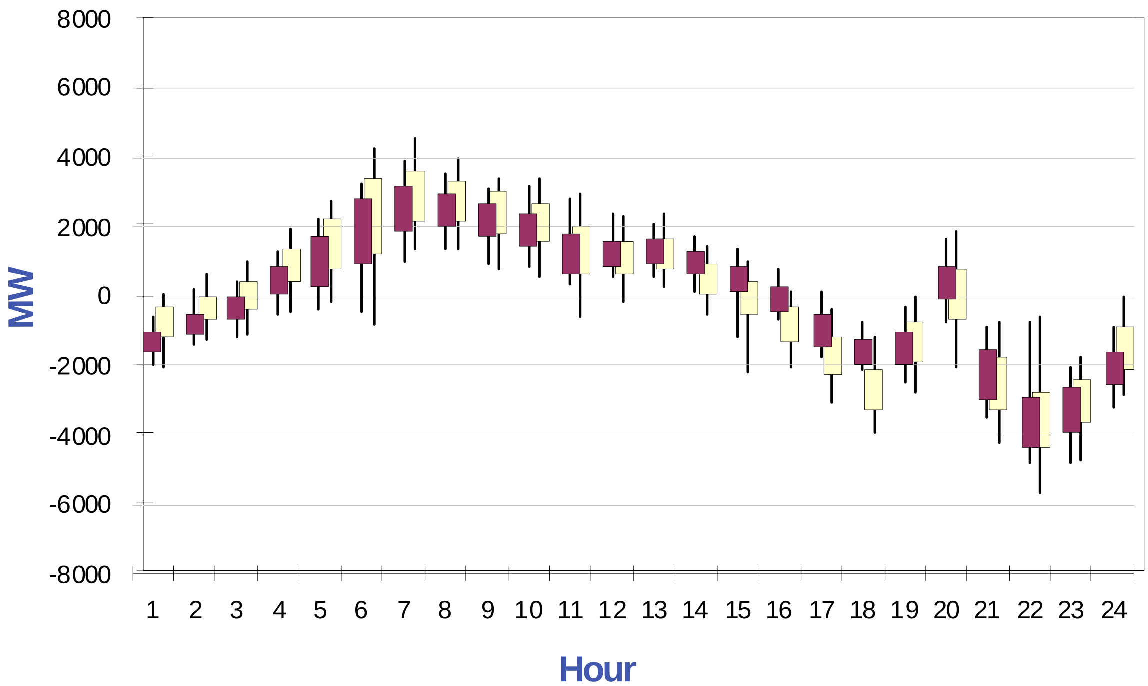


**Figure 25. 2010X July Hourly Load and Net Load Delta Stock Chart by Hour of Day.**

Figure 26 is based on all January days in the three study years of 2002, 2003, and 2004 for the 2010X scenario. It shows that the average 'Holiday Light' net load rise at 6 pm is about 440 MW/hr or 12% higher than the average load alone rise of 3600 MW/hr. The maximum net load rise is about 1350 MW/hr or 25% higher than the maximum load alone rise of 5300 MW/hr.

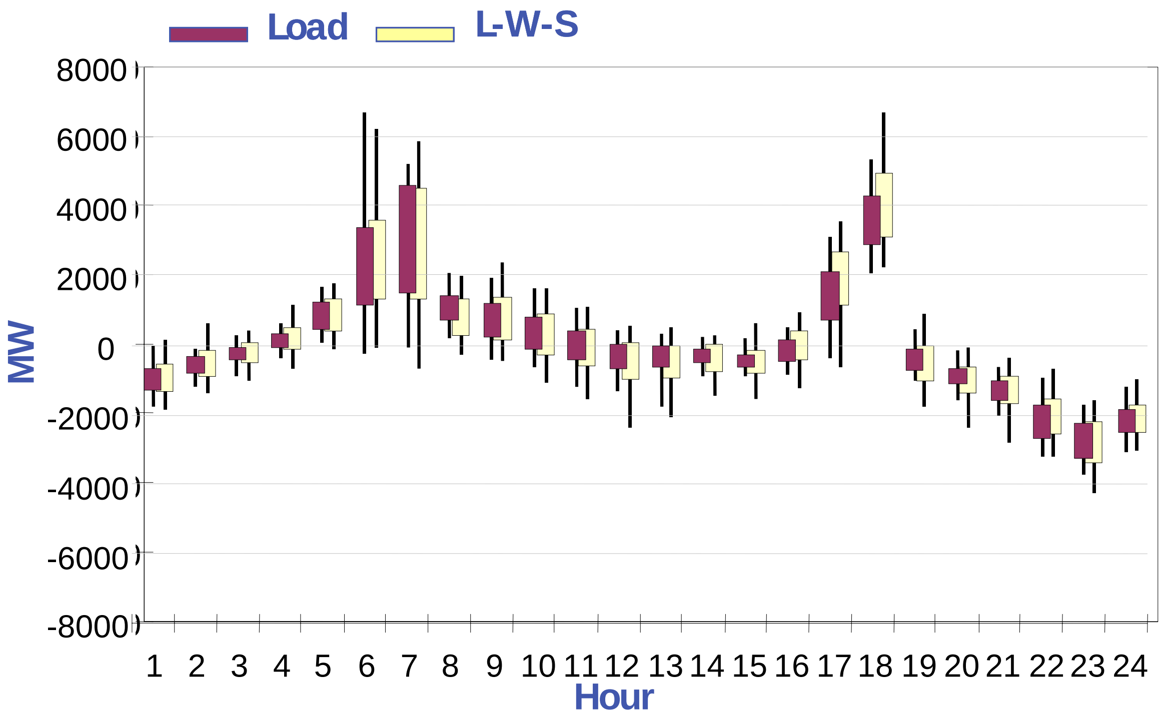


**Figure 26. 2010X January Hourly Load and Net Load Deltas Stock Chart by Hour of Day.**

### *Sustained 3-Hour Changes*

Figure 20 showed an illustrative summer day in July 2002. As noted previously, this particular summer morning has a relatively high rate of morning load rise, which reaches a maximum of about 3,600 MW/hr in the 7th hour (blue line with square symbol). The next few hours have about the same level of hourly load rise. The peak 3-hour period of load rise is during the 6th, 7th and 8th hours. The 3-hour load delta during this period is about 9,300 MW/3hrs. The 3-hour net load delta during this period is about 9,900 MW/3hrs. Sustained load increases and decreases represent a challenging operating condition. Thus, the impact of the intermittent renewables on 3-hour load deltas was evaluated further.

Figure 27 shows 3-hour deltas for the 2010X load (red) and net load (yellow) scenarios based on all study years (2002, 2003, 2004) relative to time-of-day. The maximum 3-hour net load rise at 6 pm increased by about 2,000 MW/3hrs from the maximum 3-hour load rise of about 8,000 MW/3hrs. At 8am, the maximum net load delta also increased by about 2,000 MW/3hrs from the maximum 3-hour load delta of 10,000 MW/3hrs. However, the overall maximum net load delta of about 12,000 MW/3hrs is only 1,000 MW/3hrs greater than the overall maximum load delta of about 11,000 MW/3hrs.

Similarly, the minimum net load delta at 7 pm increased by about -3,000 MW/3hrs from the minimum load delta about –6,000 MW/3hrs. At 11pm, the minimum net load delta increased by about -1,000 MW/3hrs from the minimum load delta of about -13,000 MW/3hrs. Hence, the overall minimum load delta has increased from about –13,000 MW/3hrs to an overall minimum net load delta of about -14,000 MW/3hrs.

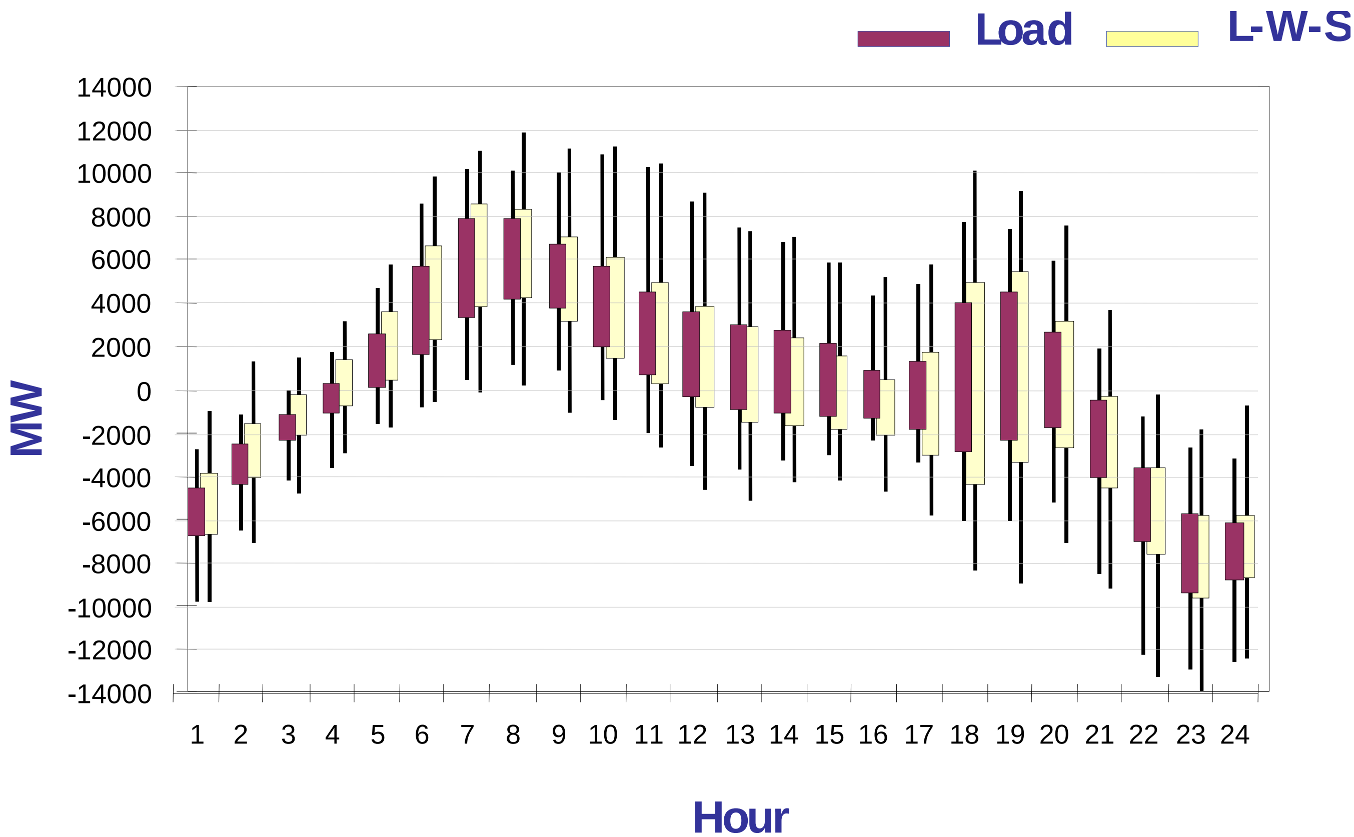


**Figure 27. 2010X 3-Hour Load and Net Load Deltas Stock Chart by Hour of the Day.**

Figure 28 shows 3-hour deltas for the 2010X load (red) and net load (yellow) scenarios in January, relative to time-of-day. As expected, the 3-hour deltas during the 'Holiday Light' evening load rise are larger than the hourly deltas. The maximum 3-hour net load rise at 6 pm increased by about 2,000 MW/3hrs from the maximum 3-hour load rise of about 8,000 MW/3hrs. However, the overall maximum is still observed in the morning. At 7am, the maximum net load delta increased by about 1,000 MW/3hrs from the maximum 3-hour load delta of 10,000 MW/3hrs. Hence, the overall maximum net load delta is about 11,000 MW/3hrs.

The minimum net load 3-hour deltas increase in several time periods by about -2,000 MW/3hrs. The overall minimum net load 3-hour delta increased by about -2,000 MW/3hrs from the minimum load delta of about –8,000 MW/3hrs. Hence, the overall minimum net load delta is about –10,000 MW/3hrs.

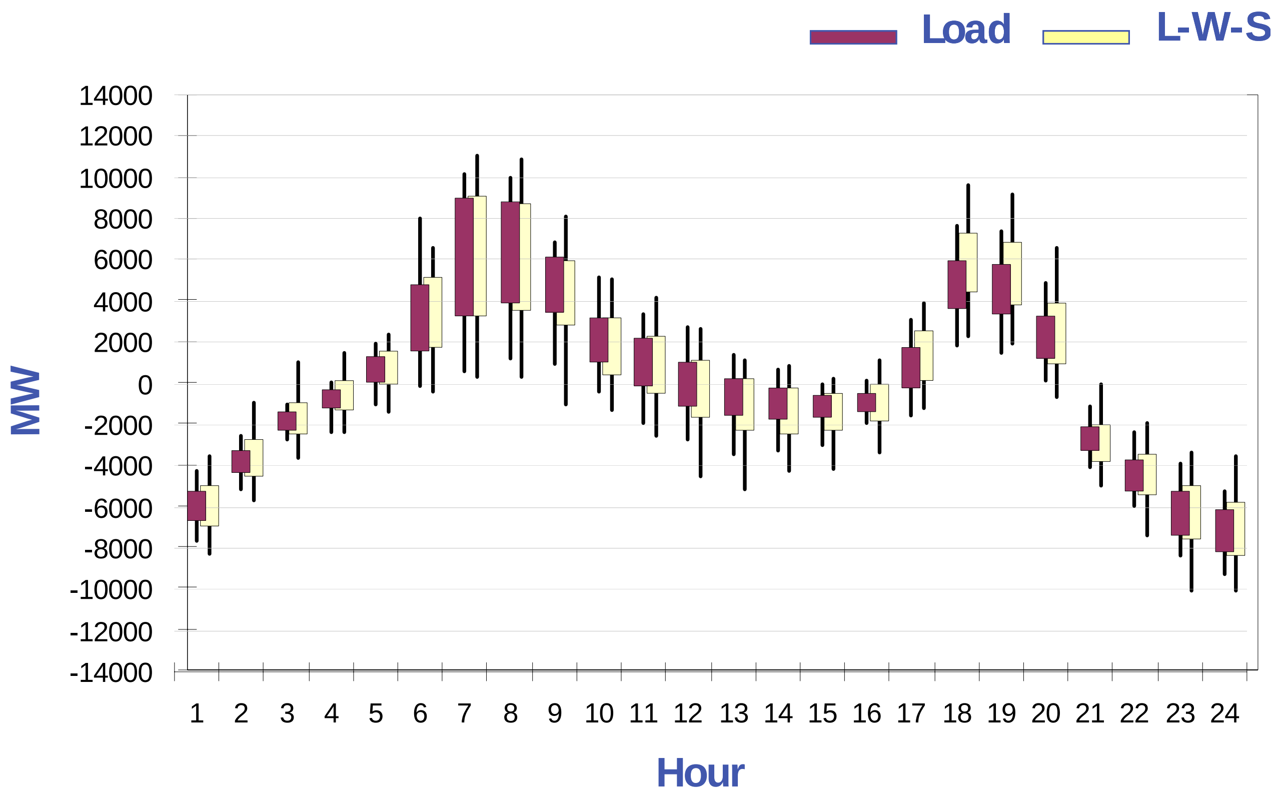


**Figure 28. 2010X January 3-Hour Load and Net Load Deltas Stock Chart by Hour of the Day.**

### *Extreme Changes*

The system must be prepared for extremes of load and renewable conditions. One useful means of characterizing the severity and frequency of events is with delta duration curves. Selected net load increase and decrease examples are presented in this section. The 2004 study year load, wind and solar shapes are presented as representative. All years were analyzed.

First, extremes of 3-hour net load rise are examined, since these may present one of the more severe system challenges. Figure 29 shows 3-hour positive delta duration curves for study year 2004 and the 2010 load alone, 2010T net load, and 2010X net load scenarios. The y-axis represents the number of hours with a positive change, of load or net load, that exceeds the level shown in the x-axis. For example, both the 2010 load (green line) and 2010T net load (pink line) scenarios have about 300 hours with 3-hour positive deltas in excess of 7,000 MW. The 2010X net load (blue line) scenario has about 300 hours with 3-hour positive deltas in excess of 7,500 MW.

The maximum load alone 3-hour positive delta is about 9,500 MW. The 2010T net load scenario has about 2 hours with 3-hour positive deltas above that level, and the 2010X net load scenario has about 10 hours. Therefore, net load 3-hour positive deltas higher than the projected load-only maximum are relatively infrequent.

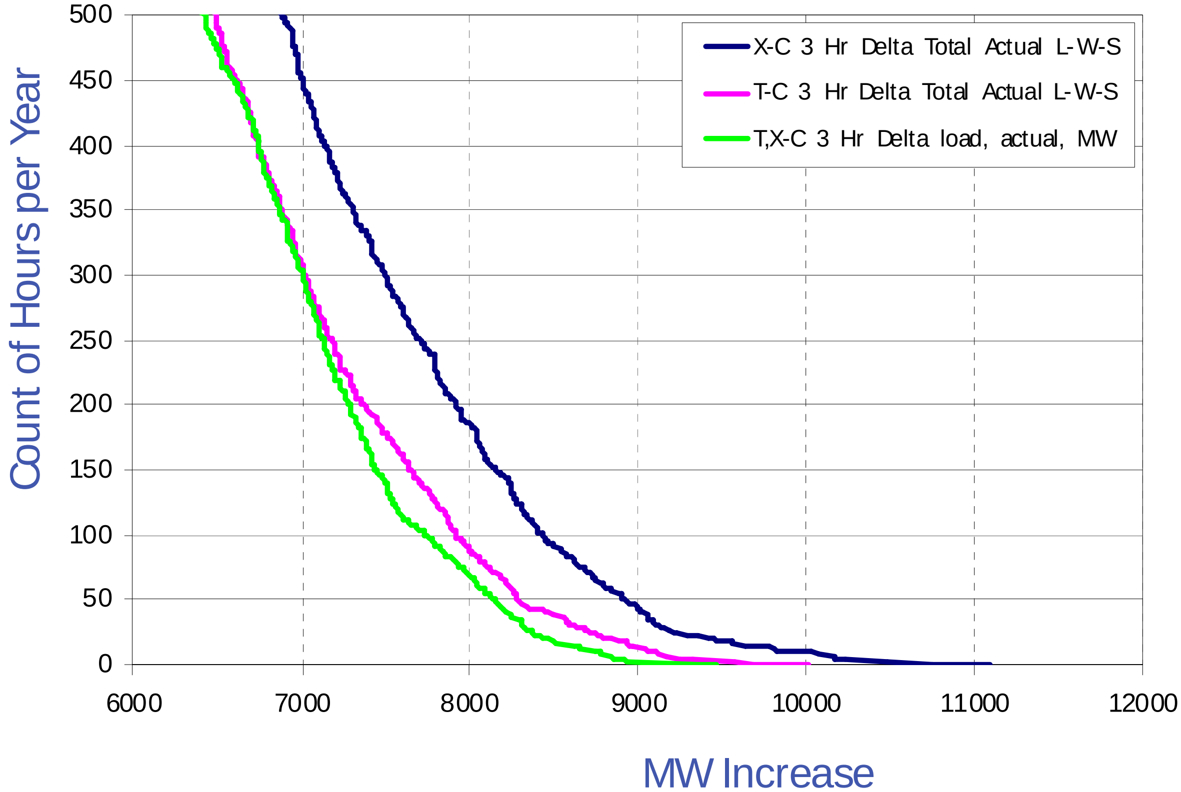


**Figure 29. 2010 3-Hour Positive Load and Net Load Delta Duration Curves for 2004.**

Figure 30 shows 3-hour negative wind delta duration curves for the 2010T and 2010X scenarios (2004 study year). These are of interest because decrease of wind power that occurs simultaneously with load increase aggravates the operations challenge. Again, the y-axis represents the number of hours with a negative change in wind that exceeds the MW level on the x-axis. The maximum negative 3-hour wind deltas are about 2,600 MW for the 2010T scenario and about 4,300 MW for the 2010X scenario. Comparing Figure 29 and Figure 30 clearly shows that coincident extreme load rise and wind decline are not to be expected.

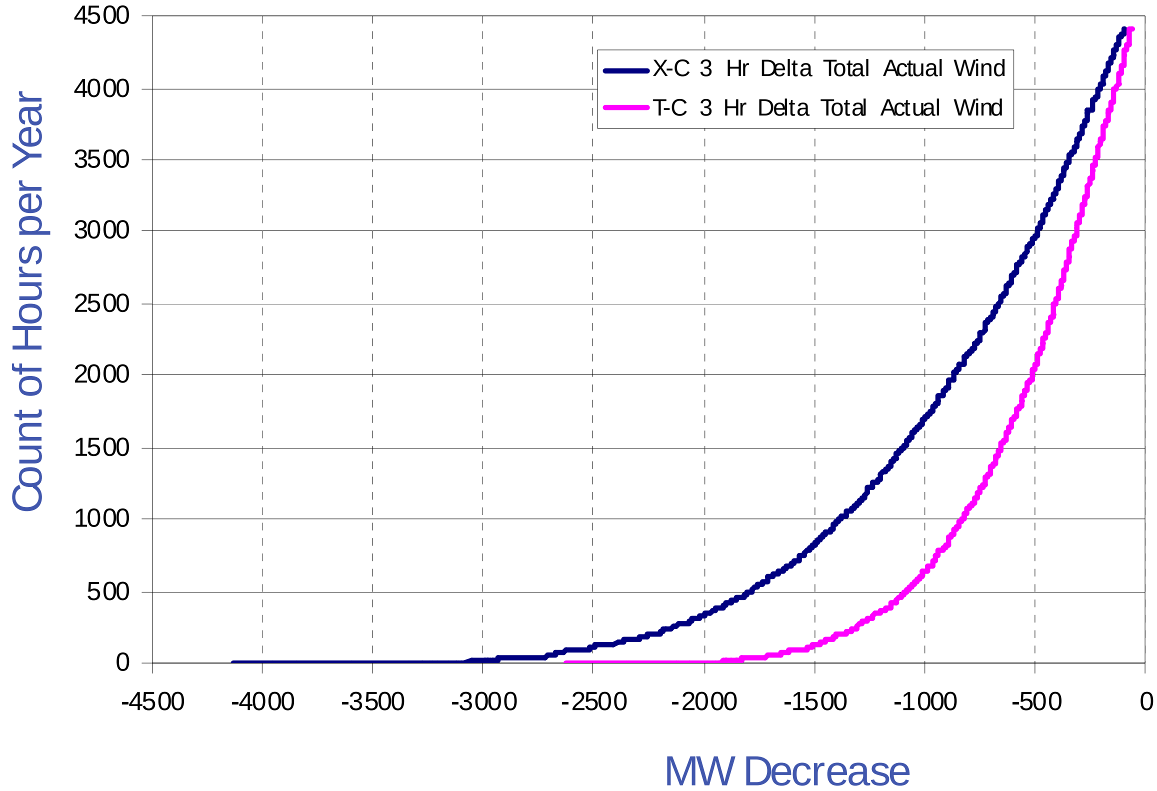


**Figure 30. 2010 3-Hour Negative Wind Delta Duration Curves for 2004 Study Year.**

Rapid load decline could also be problematic. For load decline, shorter time windows are of concern. Figure 31 shows 1-hour negative delta duration curves for study year 2004 and the 2010 load alone, 2010T net load, and 2010X net load scenarios. the y-axis represents the number of hours with a negative change, in either load or net load, that exceeds the MW level on the x-axis. The minimum 1-hour negative delta is about 5,400 MW for all three scenarios.

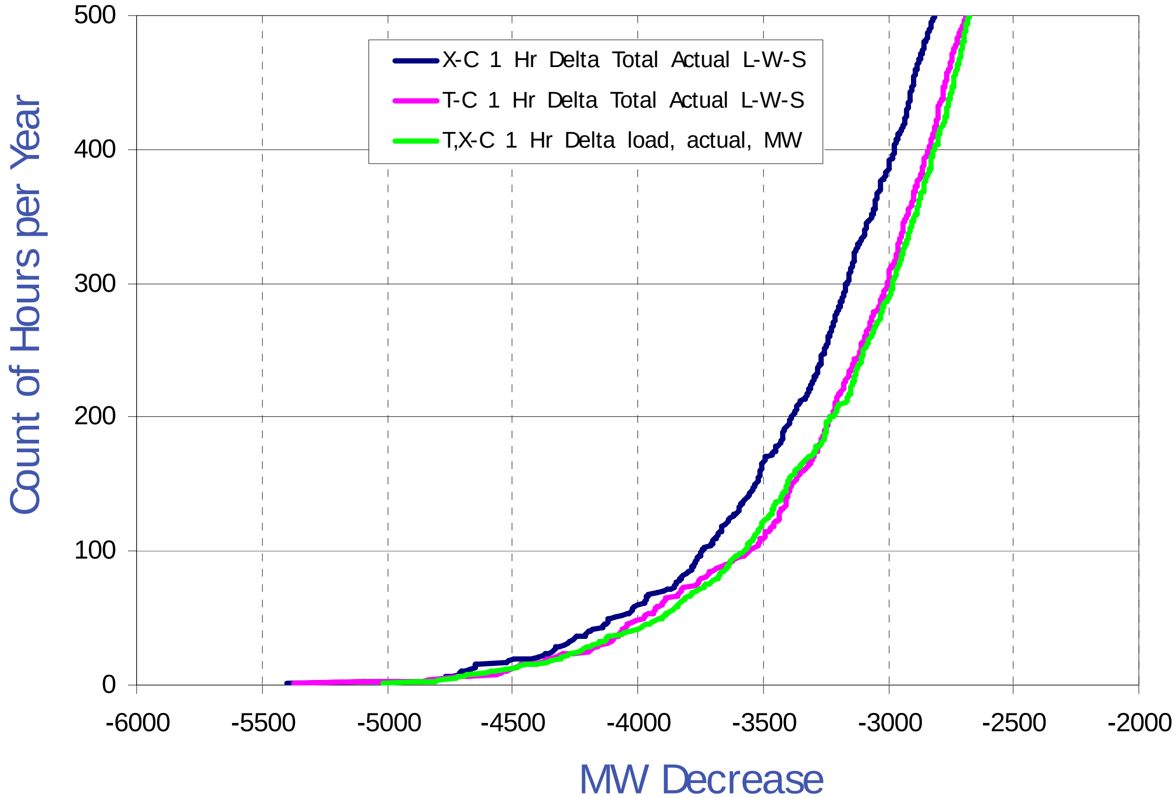


**Figure 31. 2010 1-Hour Negative Load and Net Load Delta Duration Curves for 2004.**

Figure 32 shows 1-hour positive wind delta duration curves for the 2010T and 2010X scenarios (2004 study year). As before, the y-axis represents the number of hours with a negative change in wind that exceeds the MW level on the x-axis. The maximum positive 1-hour wind deltas are about 2,100 MW for the 2010T scenario and 3,500 MW for the 2010X scenario. As with the net load rise, it is clear that extremes of wind are not expected to coincide with extremes of load decline.

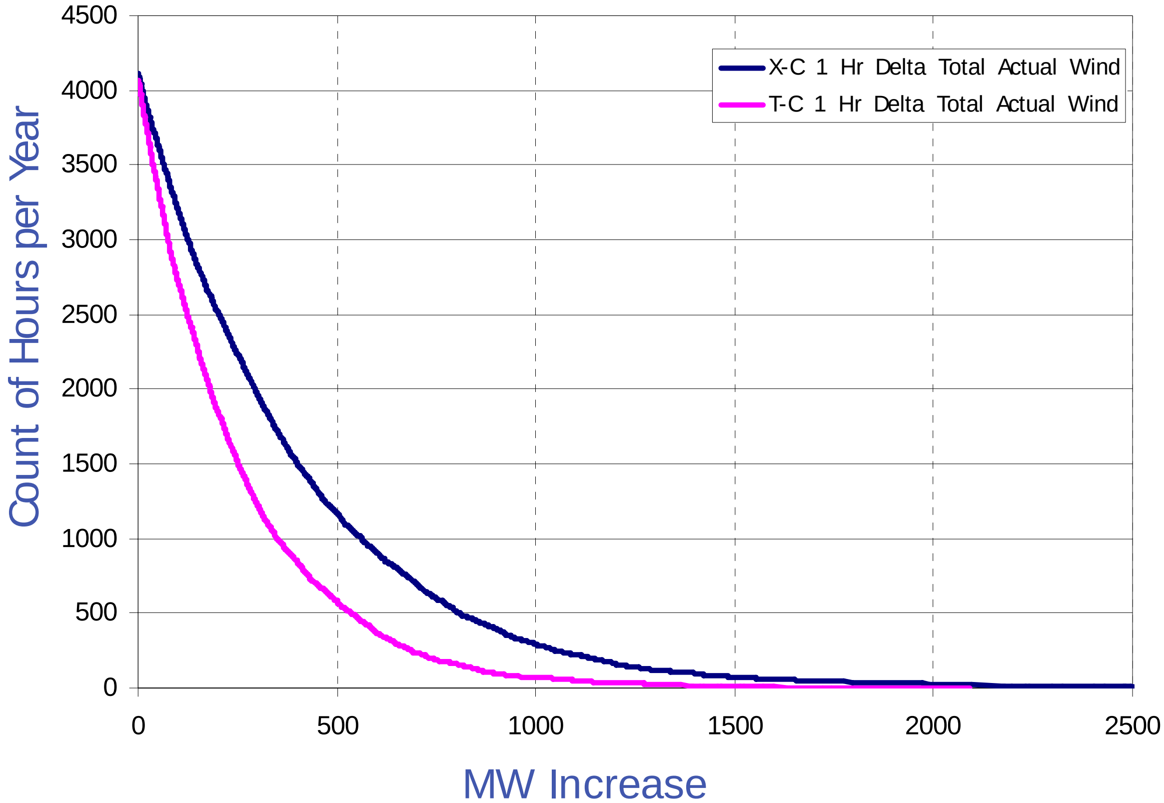


**Figure 32. 2010 1-Hour Positive Wind Delta Duration Curves for 2004 Study Year.**

### *3.2.3. 2020 Variability Relative to Load Level and Time-of-Day*

Figure 33 shows another "open-high-low-close" stock chart for the 2020 load and net load scenario. The red bars represent the load scenario and the yellow bars represent the net load (L-W-S) scenario. The top of a bar represents the average value of hourly delta plus the standard deviation. The bottom of a bar represents the average value of hourly delta minus the standard deviation. The top of a vertical line represents the maximum hourly deltas, and the bottom of a vertical line represents the minimum hourly delta.

The chart shows that wind and solar have the most impact on hourly variation, including extremes, under light load conditions. The standard deviation of the load alone variability for the 10th decile is 920 MW. It increases by 324 MW to 1244 MW with the addition of the intermittent renewables. Therefore, under light load, there is a 99.7% expectation (3σ) that hour-to-hour changes will be less than ±2760 MW with the load alone, and ±3732 MW with the additional wind and solar. The maximum hourly delta is 2349 MW for load alone, and 3923 MW for net load. The minimum hourly delta is -3533 MW for load alone, and -5100 MW for net load. The maximum and minimum hourly deltas, for both load and net load, exceed the 3σ expectation (99.7%) under light load conditions. Broadly, the system requires hourly schedule flexibility at light load of about ±4000 MW by 2020.

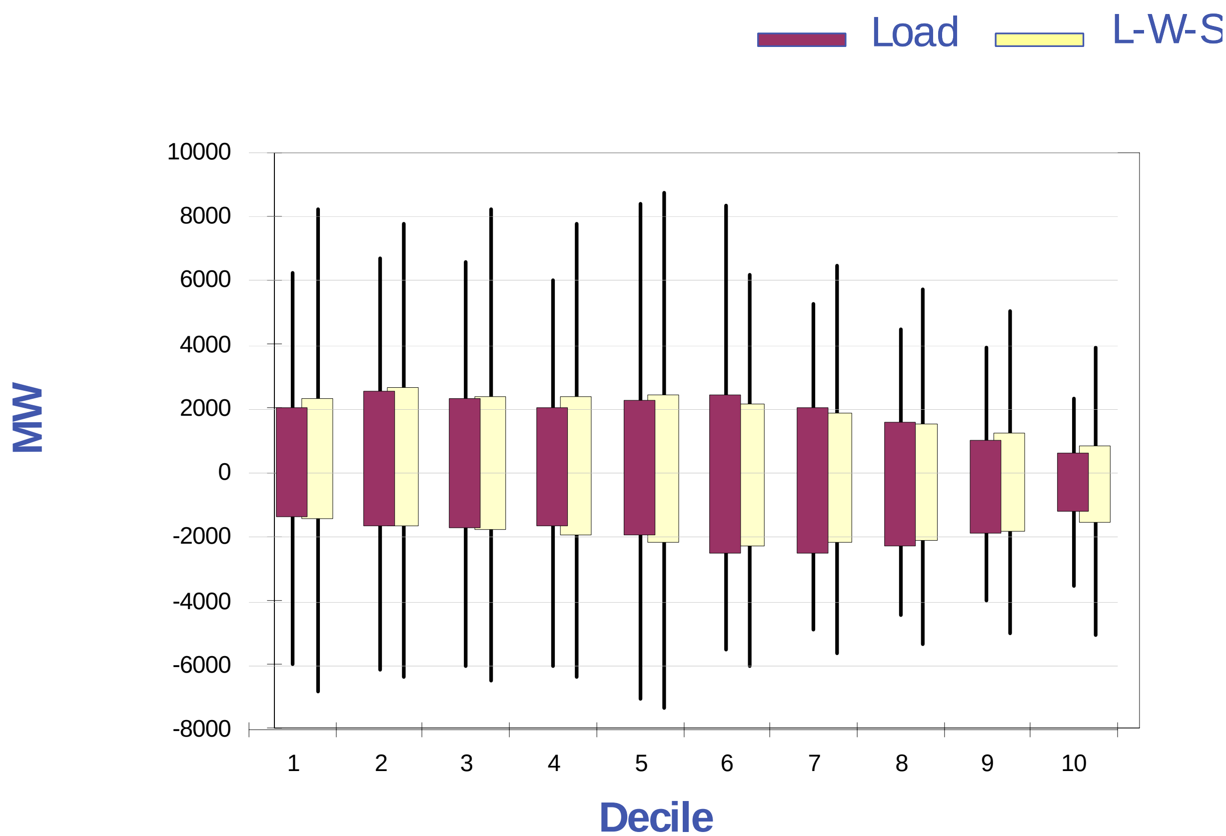


**Figure 33. 2020 Hourly Load and Net Load Deltas Stock Chart by Decile.**

Figure 34 shows hourly deltas for the 2020 load and net load scenarios based on all January days in the three study years of 2002, 2003, and 2004. This figure shows the 2020 hourly load deltas (red) and hourly net load deltas (yellow) by time of day. Note that the 'Holiday Light' average load rise at 6 pm increases by about 500 MW/hr, or 11% based on an average load rise of 4,500 MW/hr, with the addition of the intermittent renewables. The maximum evening hourly delta increases by about 1,500 MW/hr, or 22% based on maximum load rise 6,700 MW/hr, with wind and solar.

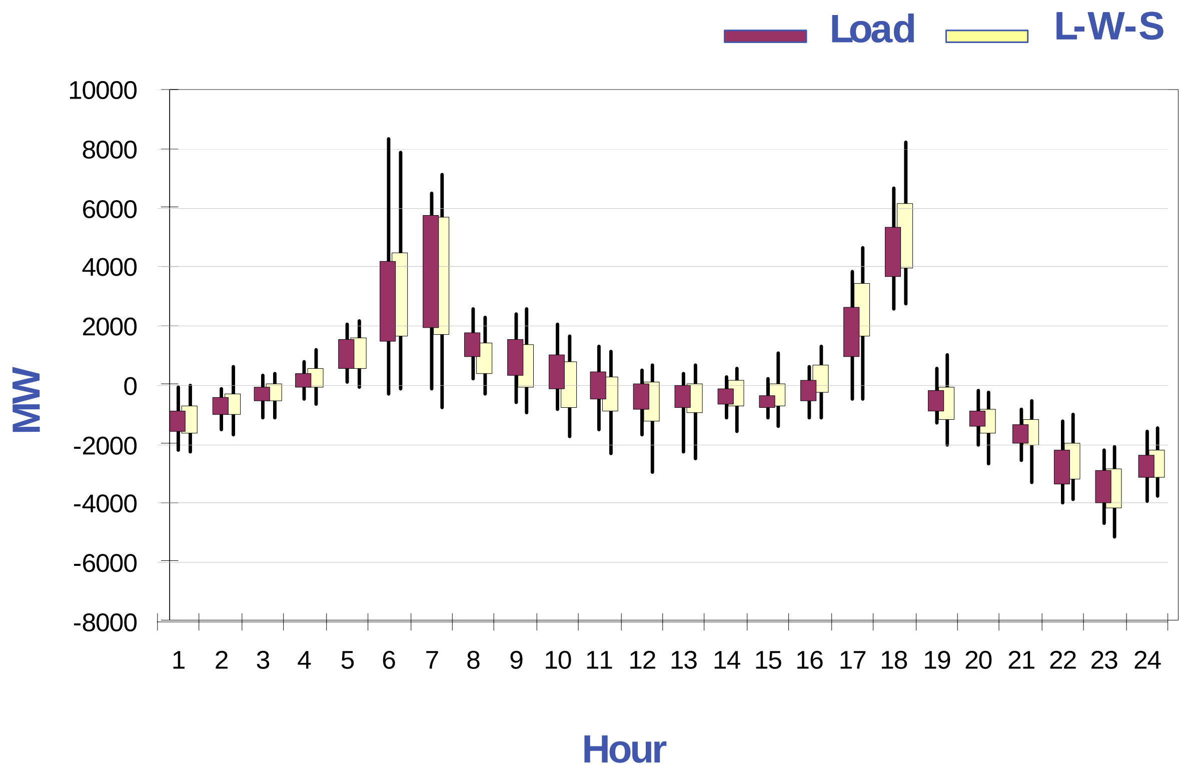


**Figure 34. 2020 January Hourly Load and Net Load Deltas Stock Chart by Hour of Day.**

Table 10 shows the 2020 hourly load statistical results, grouped into ten deciles on the basis of load alone. The 10 percent of peak load hours are included in decile 1, and the 10 percent of light load hours are included in decile 10. The table shows the maximum, minimum, and average load as well as the standard deviation (σ), maximum, and minimum 1-hour load deltas.

Table 11 shows the 2020 hourly net load, wind and solar statistical results, grouped into ten deciles on the basis of L-W-S. The first rows in the table show the maximum, minimum, and average net load (L-W-S). The next row shows the average load alone in each L-W-S decile. This average is different from the average load shown in Table 10 because deciles sorted by L-W-S are different from deciles sorted by load alone. The remaining rows show the standard deviation (σ), maximum and minimum 1-hour net load deltas as well as the average wind production and penetration, and the average solar production and penetration.

All 2020 hourly variability figures cited in this report are from these tables.

**Table 10. 2020 Hourly Load Statistics (MW).**

| | Load Decile | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Trait** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **All Year** |
| **Maximum** | 66215 | 50612 | 46107 | 43844 | 42188 | 40502 | 38226 | 35910 | 33876 | 31754 | 66215 |
| **Minimum** | 50616 | 46110 | 43846 | 42189 | 40502 | 38227 | 35910 | 33877 | 31755 | 26758 | 26758 |
| **Average** | 55273 | 48160 | 44862 | 42993 | 41373 | 39438 | 37035 | 34891 | 32809 | 30357 | 40719 |
| **σ Delta** | 1725 | 2140 | 2024 | 1876 | 2140 | 2500 | 2289 | 1976 | 1480 | 920 | 1977 |
| **Maximum Delta** | 6233 | 6680 | 6573 | 6021 | 8427 | 8355 | 5262 | 4466 | 3939 | 2349 | 6233 |
| **Minimum Delta** | -5965 | -6118 | -6031 | -6016 | -7049 | -5528 | -4866 | -4404 | -3947 | -3533 | -7049 |
| **Average Delta** | 310 | 437 | 288 | 179 | 161 | -28 | -245 | -360 | -426 | -315 | 0.1 |

**Table 11. 2020 Hourly Net Load and Intermittent Renewable Statistics (MW or %).**

| | Net Load Decile | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Net Load (L-W-S) Trait** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **All Year** |
| **Maximum** | 61290 | 44529 | 40692 | 38346 | 36333 | 34262 | 32233 | 30388 | 28462 | 26183 | 61290 |
| **Minimum** | 44529 | 40693 | 38347 | 36333 | 34262 | 32234 | 30388 | 28463 | 26185 | 18400 | 18400 |
| **Average** | 48928 | 42399 | 39449 | 37339 | 35309 | 33220 | 31288 | 29434 | 27383 | 24230 | 34898 |
| **Load Alone Average** | 54691 | 47543 | 44465 | 42836 | 41249 | 39290 | 37202 | 34966 | 33327 | 31623 | 40719 |
| **σ Delta** | 1904 | 2203 | 2099 | 2198 | 2327 | 2276 | 2037 | 1860 | 1549 | 1244 | 2019 |
| **Maximum Delta** | 8216 | 7779 | 8261 | 7797 | 8747 | 6203 | 6483 | 5701 | 5025 | 3923 | 8216 |
| **Minimum Delta** | -6869 | -6393 | -6515 | -6424 | -7351 | -6080 | -5670 | -5359 | -5030 | -5100 | -7351 |
| **Average Delta** | 411 | 442 | 259 | 180 | 92 | -110 | -194 | -352 | -333 | -394 | 0.1 |
| **Wind Average** | 2891 | 3294 | 3365 | 3972 | 4530 | 4884 | 4893 | 4919 | 5539 | 7060 | 4535 |
| **Wind Penetration** | 5.29% | 6.93% | 7.57% | 9.27% | 10.9% | 12.4% | 13.2% | 14.1% | 16.6% | 22.3% | 11.1% |
| **Solar Average** | 2873 | 1850 | 1651 | 1525 | 1410 | 1186 | 1021 | 612 | 405 | 329 | 1286 |
| **Solar Penetration** | 5.25% | 3.89% | 3.71% | 3.56% | 3.42% | 3.02% | 2.74% | 1.75% | 1.22% | 1.04% | 2.16% |

## 3.3. Intra-Hour Variability

A detailed analysis of selected 3-hour periods exhibiting interesting behavior was performed. The definition of interesting behavior included:

- Large 1-hour and 3-hour changes in load
- High levels of wind and solar output
- High penetration of wind and solar
- Light load
- Large 1-hour and 3-hour changes in wind and solar
- Sustained high levels of wind output with low variability

Specific 3-hour periods were selected from the top 20 of each category for variety in study year, season, time of day, type of behavior (e.g., large change or high penetration), direction of change (e.g., positive or negative).

### 3.3.1. Selected Periods

The selected 3-hour periods are identified on the three 2010 load duration curves shown in Figure 35. The selected periods are distributed across the load deciles. Thus, high load, light load, and intermediate load (often periods with large changes) are all represented. The three 3-hour periods selected for the quasi-steady state (QSS) analysis are highlighted, and discussed in detail in Section 5.1.1.

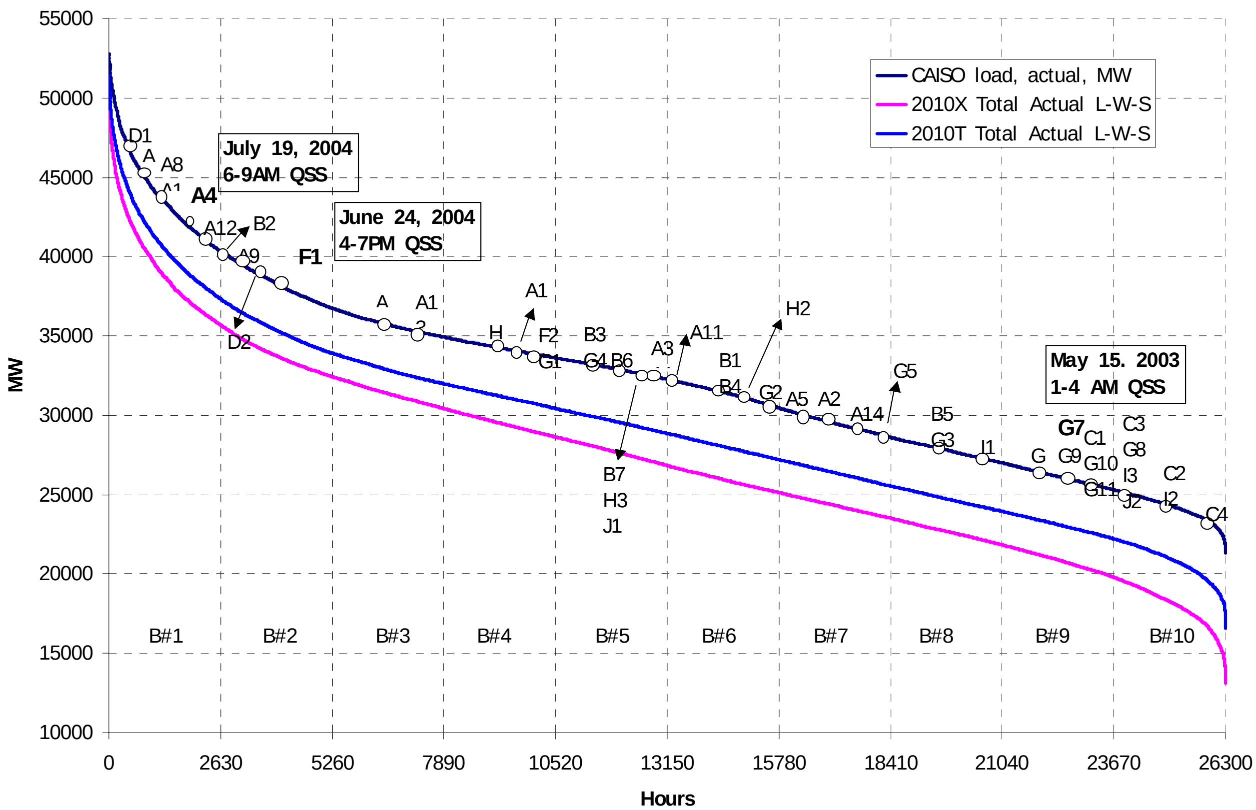


**Figure 35. 2010 Load Duration Curves with 3-Hour Periods of Interest Identified.**

For each selected 3-hour period, 1-minute profiles were developed for each wind and solar resource and 1-minute data for California ISO load was provided. For illustration, Figure 36 shows a specific 3-hour period, 6am to 9am, in July 2003. In the morning, load increases at a rate of about 10,000 MW/3hrs, while the wind decreases at a rate of about 600 MW/3hrs.

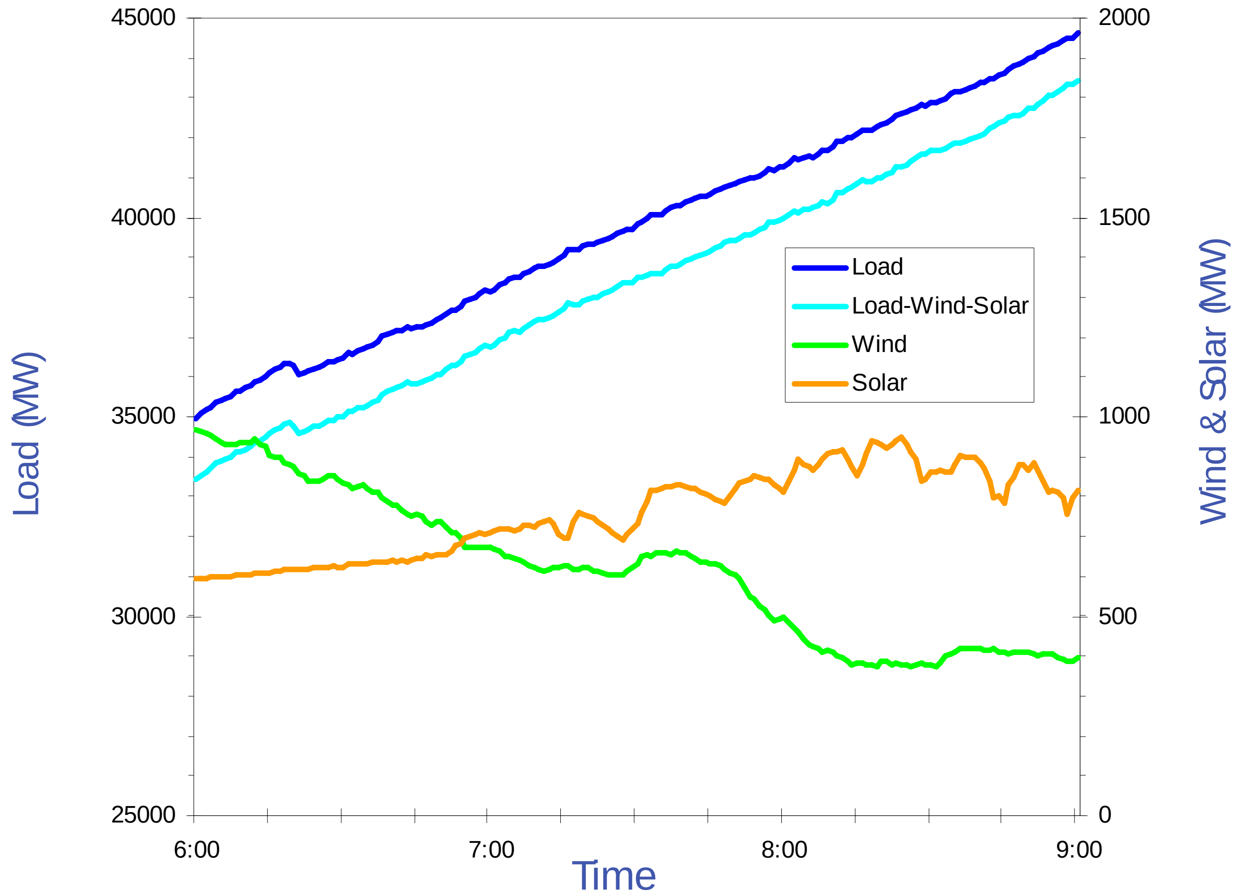


**Figure 36. 1-Minute Profiles During 3-Hour Period of Example July 2003 Day.**

### *3.3.2. Intra-Hour Variability Definitions*

After the 1-minute wind and solar profiles and load data were synchronized, a sub-hourly statistical analysis was performed on the load alone, wind alone, and net load. The analysis was similar to that performed on the 1-hour data and described in previous sections.

Figure 37 uses an example 1-minute profile (red line with black dots) to define the load-following metric used in this analysis. The first step in developing this metric was to calculate the 15 minute rolling average (blue line) of the 1-minute data. Then, a 5-minute delta was calculated based on the 15-minute rolling average. For example, the rolling average at time equal to 5 minutes is about 42MW. Five minutes later, the rolling average is about 52MW. Thus the 5-minute delta, or load-following metric, is about 10 MW.

The same figure can be used to describe the regulation metric used in this study. Again, the first step in developing this metric was to calculate the 15 minute rolling average of the 1-minute data. Then, the 1-minute delta between the data and the 15-minute rolling average was calculated. For example, the rolling average at time equal to 14 minutes is about 56MW. The data at this time is about 40 MW. Thus the 1-minute delta, or regulation metric, is about -16MW.

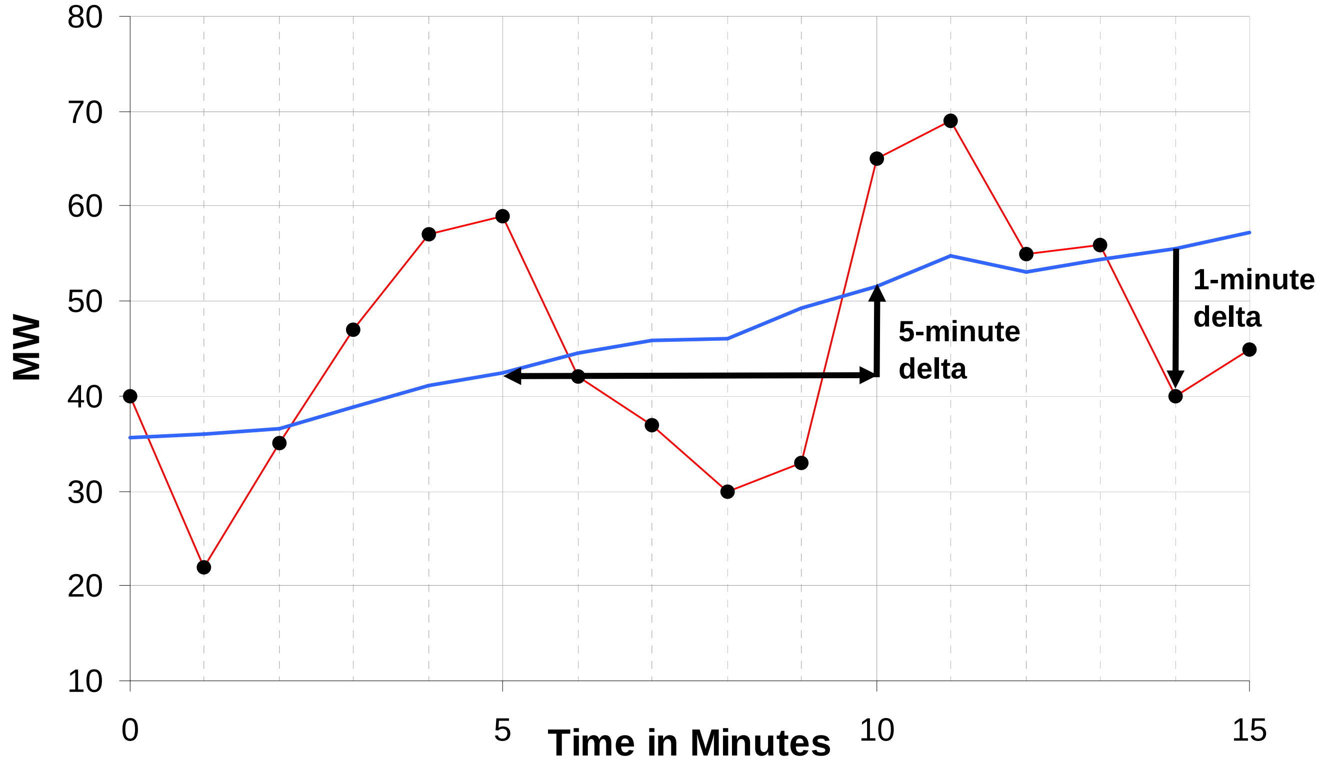


**Figure 37. Example for Load-Following and Regulation Metric Definition.**

As an example, Figure 38 shows the 5-minute deltas on the 15 minute rolling average for the load, net load, wind, and solar data on a July morning. The left y-axis scale applies to the load and net load, the right y-axis scale applies to the wind and solar. The load following requirement (i.e., 5-minute deltas) ranges from 120 MW to 400 MW per 5 minutes. The wind delta is generally negative, and the solar delta is generally positive.

The 5-minute statistical results associated with this study period are shown in Table 12. The standard deviation of net load 5-minute delta is 2 MW less than the load alone 5-minute delta standard deviation of 54 MW.

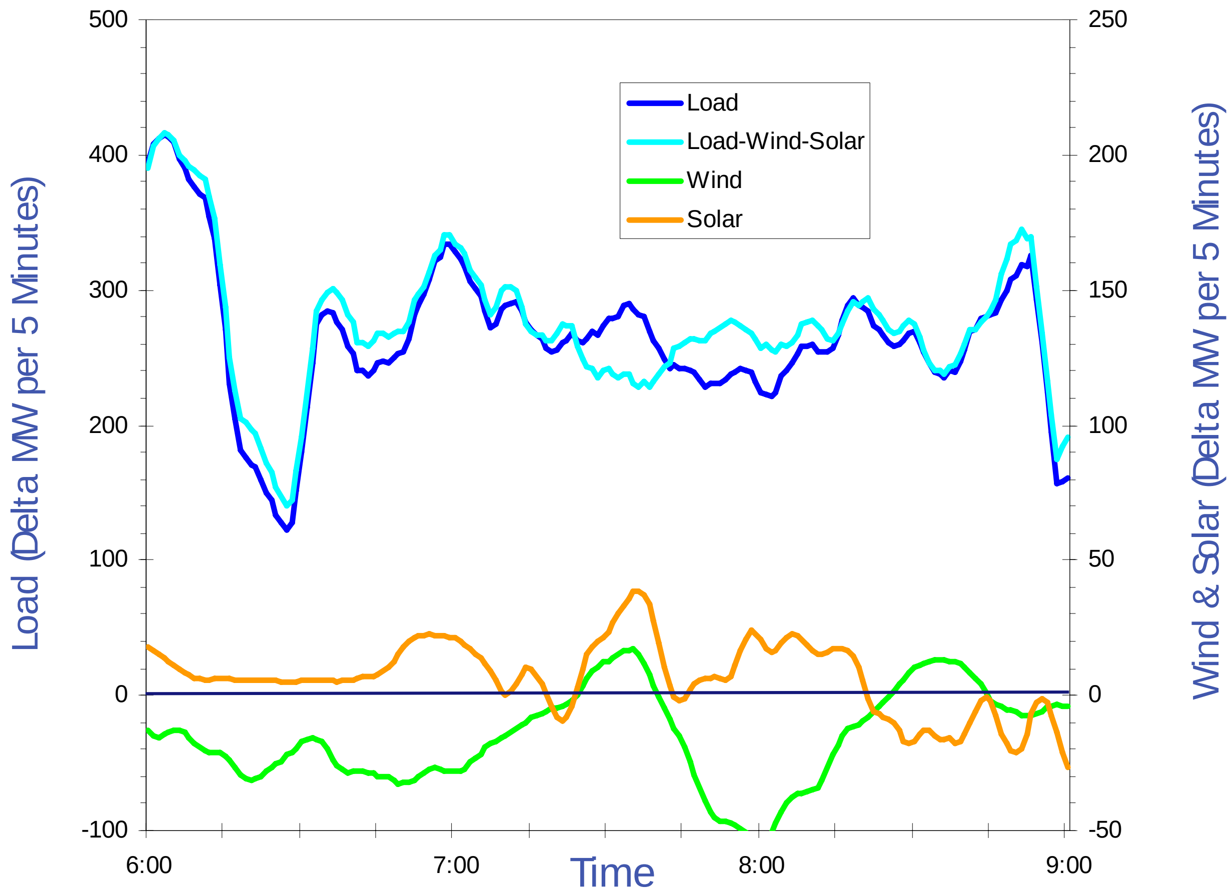


**Figure 38. Load–Following Requirement for July 2003 Example 3-Hour Period.**

**Table 12. Statistics on Load Following Requirement for July 2003 Example 3-Hour Period.**

| | Mean (MW) | σ (MW) |
|---|---|---|
| **Load** | 265 | 54 |
| **Wind** | -16 | 18 |
| **Solar** | 7 | 13 |
| **L-W-S** | 275 | 52 |

For the same study period, Figure 39 shows the 1 minute deltas from the 15 minute rolling average for the load, net load, wind and solar data. The left y-axis scale applies to the load and net load, the right y-axis scale applies to the wind and solar. The 1-minute wind delta is within ±20 MW/per minute, and the 1-minute solar delta ranges between ±60 MW/per minute.

The 1-minute statistical results associated with this study period are shown in Table 13. The standard deviation of net load 1-minute delta is about 5 MW large than the 1-minute load alone delta standard deviation of 56 MW.

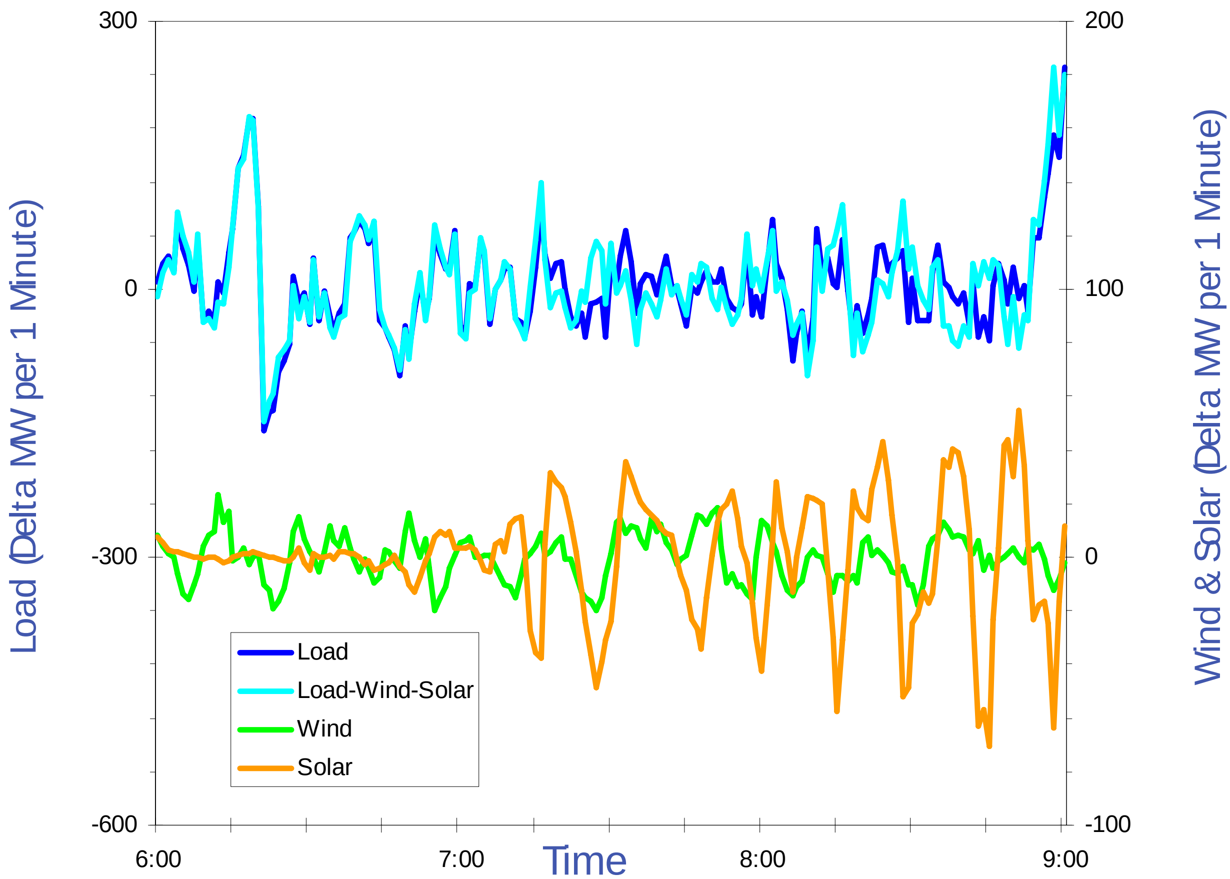


**Figure 39. Regulation Requirement for July 2003 Example 3-Hour Period.**

**Table 13. Statistics on Regulation Requirement for July 2003 Example 3-Hour Period.**

| | Mean (MW) | σ (MW) |
|---|---|---|
| **Load** | 6.5 | 56 |
| **Wind** | -0.3 | 9 |
| **Solar** | 0.0 | 22 |
| **L-W-S** | 6.8 | 61 |

### *3.3.3. 2010X Variability at Light Load*

The section focuses on the load following requirements (i.e., 5-minute deltas) for the 2010X scenario under light load conditions. Figure 40 shows the 5-minute delta duration curves for load alone, net load and wind under those conditions. The y-axis shows the percent of light load hours with a 5-minute delta larger than the MW level shown on the x-axis. Both positive and negative 5-minute deltas are shown on the x-axis. Load decreases are more important than load increases at light load in the load following/economic dispatch (5-minute) time frame. The load alone (light blue line) and net load (pink line) duration curves are similar. The largest 5-minute load alone and net load decreases are both about -600 MW.

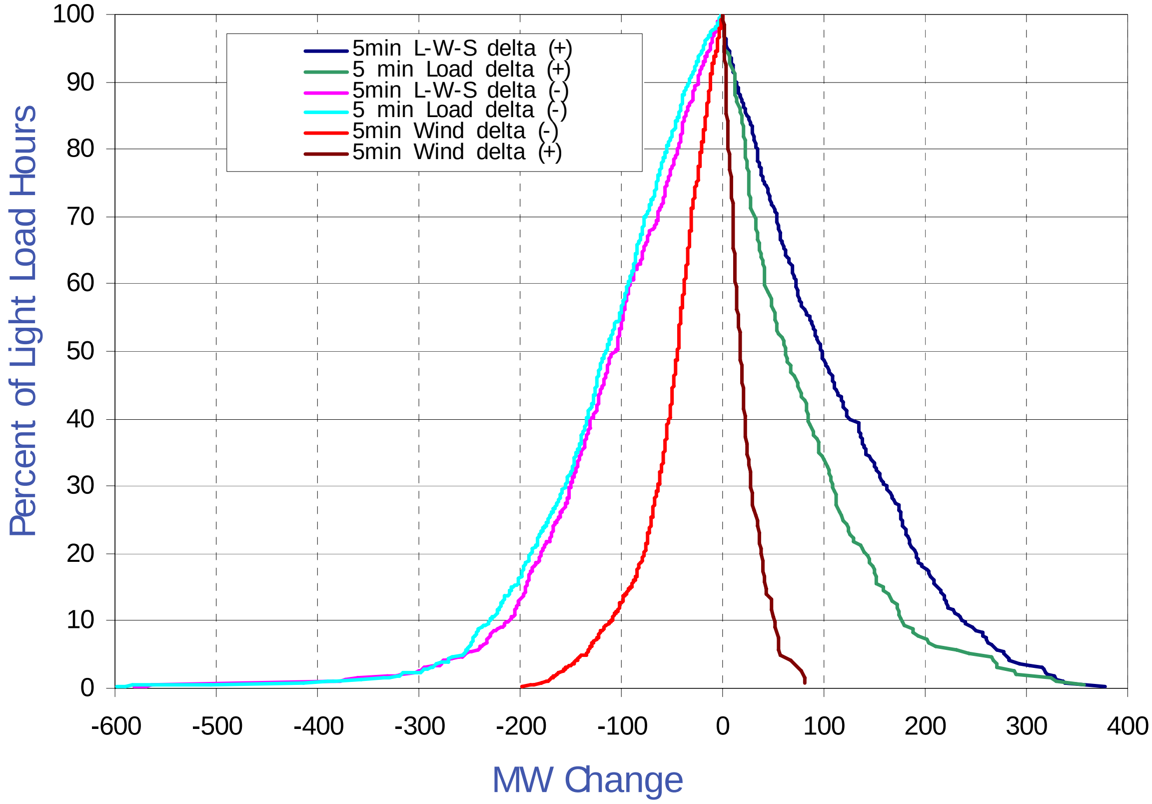


**Figure 40. 2010X 5-Minute Delta Duration Curves for Light Load (10th Decile).**

Figure 41 shows the 1-minute delta duration curves for load alone, net load and wind under 2010X light load conditions. Again, the y-axis shows the percent of light load hours with a 1-minute delta larger than the MW level shown on the x-axis. Both positive and negative 1-minute deltas are shown on the x-axis. Load decreases remain more important than load increases in the regulation (minute-to-minute) time frame. The load alone (light blue line) and net load (pink line) duration curves are similar. The largest 1-minute decreases in both load and net load are about -350 MW.

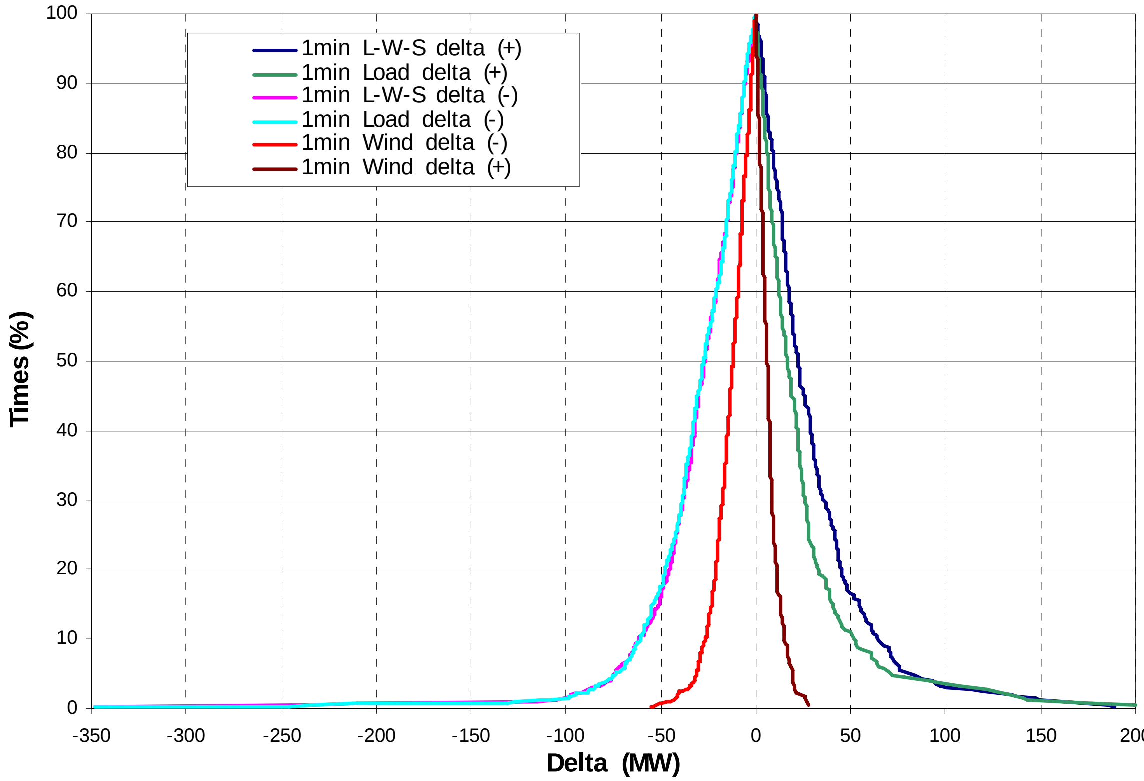


**Figure 41. 2010X 1-Minute Delta Duration Curves for Light Load (10th Decile).**

Figure 42 shows 1-minute and 5-minute wind delta duration curves for 2010X light load conditions. Again, the y-axis shows the percent of light load hours with a delta larger than the MW level shown on the x-axis. Both positive and negative 1-minute and 5-minute deltas are shown on the x-axis. The largest 5 –minute wind decrease is about -200 MW, approximately four times of the largest 1-minute wind decrease.

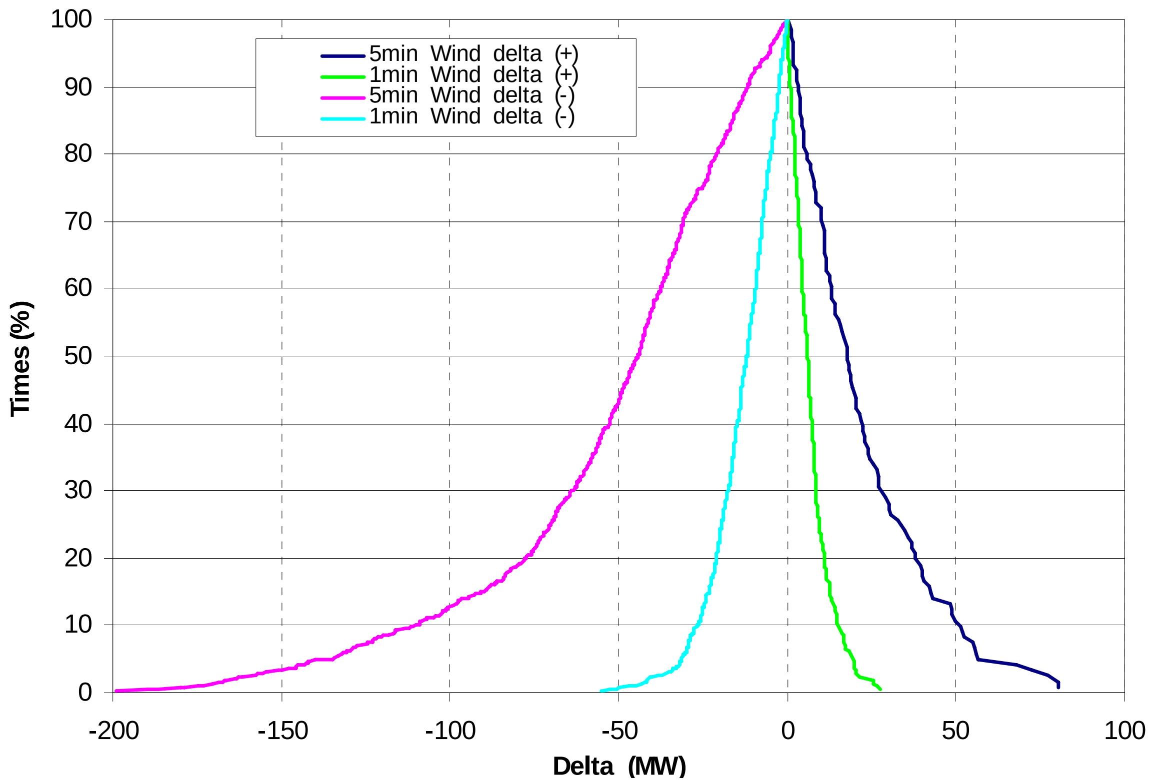


**Figure 42. 2010X Sub-Hourly Delta Wind Duration Curves for Light Load (10th Decile).**

## 3.4. Variability Summary

A summary of the hourly and sub-hourly variability for the 2006, 2010T and 2010X scenarios is shown in Table 14. The load and net load variability for each scenario, as well as the difference between them, is displayed in each set of three rows. The first three columns show the standard deviation (σ) of the 1-hour, 5-minute and 1-minute deltas. The final three columns show the maximum and minimum of the 1-hour, 5-minute and 1-minute deltas.

The maximum and minimum 1-hour net load deltas for the 2010T scenario are 402 MW and 96 MW less, respectively, than with load alone. Thus, the 2010T wind and solar scenario reduces the extreme 1-hour schedule flexibility requirements in the California ISO system.

**Table 14. Summary of 2006 and 2010 Full–Year Statistical Analysis.**

| | Standard Deviation, σ | | | Maximum, Minimum | | |
|---|---|---|---|---|---|---|
| | 1-Hour Δs (MW) | 5-Min Δs (MW) (1) | 1-Min Δs (MW) (2) | 1-Hour Δs (MW) | 5-Min Δs (MW) (1) | 1-Min Δs (MW) (2) |
| 2006 Load | 1436 | 189.3 | 44.8 | 6123, -5122 | 526, -480 | 803, -305 |
| 2006 L-W-S | 1451 | 189.9 | 44.9 | 6091, -5155 | 550, -481 | 803, -306 |
| **Change** | **15** | **0.3** | **0.1** | **-32, -33** | **24, -1** | **0, -1** |
| 2010 Load | 1575 | 207.6 | 49.1 | 6714, -5617 | 577, -527 | 881, -334 |
| 2010T L-W-S | 1623 | 214.5 | 50.7 | 6312, -5713 | 699, -522 | 887, -323 |
| **Change** | **48** | **6.9** | **1.6** | **-402, -96** | **122, 5** | **6, 11** |
| 2010 Load | 1575 | 207.6 | 49.1 | 6714, -5617 | 577, -527 | 881, -334 |
| 2010X L-W-S | 1704 | 221.8 | 52.4 | 7219, -5986 | 722, -530 | 884, -335 |
| **Change** | **129** | **14.2** | **3.3** | **505, -37** | **145, -3** | **3, -1** |

Notes: (1) 5-minute change in MW on 15-minute rolling average
(2) 1-minute difference in actual MW from 15-minute rolling average

A summary of the light load hourly and sub-hourly variability for the 2006, 2010T and 2010X scenarios is shown in Table 15. The load and net load variability for each scenario, as well as the difference between them, is displayed in each set of three rows. The first three columns show the standard deviation (σ) of the 1-hour, 5-minute and 1-minute deltas. The final three columns show the maximum and minimum of the 1-hour, 5-minute and 1-minute deltas.

**Table 15. Summary of 2006 and 2010 Light Load (10th Decile) Statistical Analysis.**

| | Standard Deviation, σ | | | Maximum, Minimum | | |
|---|---|---|---|---|---|---|
| | 1-Hour Δs (MW) | 5-Min Δs (MW) (1) | 1-Min Δs (MW) (2) | 1-Hour Δs (MW) | 5-Min Δs (MW) (1) | 1-Min Δs (MW) (2) |
| 2006 Load | 669 | 86.5 | 40.8 | 1707, -2567 | 154, -257 | 200, -194 |
| 2006 L-W-S | 699 | 89.2 | 40.9 | 2448, -2613 | 174, -257 | 198, -193 |
| **Change** | **30** | **2.7** | **0.1** | **741, -46** | **20, 0** | **-2, 1** |
| 2010 Load | 734 | 94.9 | 44.8 | 1871, -2815 | 169, -282 | 219, -213 |
| 2010T L-W-S | 933 | 109.1 | 45.9 | 2939, -3427 | 231, -259 | 213, -228 |
| **Change** | **199** | **14.2** | **1.1** | **1068, -612** | **62, 23** | **-6, -15** |
| 2010 Load | 734 | 94.9 | 44.8 | 1871, -2815 | 169, -282 | 219, -213 |
| 2010X L-W-S | 1081 | 114.7 | 47.7 | 3250, -4141 | 254, -250 | 203, -224 |
| **Change** | **347** | **19.8** | **2.9** | **1379, -1326** | **85, 32** | **-16, -11** |

Notes: (1) 5-minute change in MW on 15-minute rolling average
(2) 1-minute difference in actual MW from 15-minute rolling average

A summary of the hourly variability for the 2010T, 2010X and 2020 scenarios is shown in Table 16. For the 2010X scenario, the 1-hour net load delta standard deviation is 129 MW larger than the 2010 1-hour load alone standard deviation. This is a significantly larger difference than is observed for the 2020 scenario. Under those conditions, the standard deviation increases by 42 MW between load alone and net load. Therefore, the relative impact of intermittent renewable generation is less in the 2020 scenario than in the 2010X scenario.

**Table 16. Summary of 2010 and 2020 Hourly Statistical Analysis.**

| | Standard Deviation, σ 1-Hour Δs (MW) | Maximum, Minimum 1-Hour Δs (MW) |
|---|---|---|
| 2010 Load | 1575 | 6714, -5617 |
| 2010T L-W-S | 1623 | 6312, -5713 |
| **Change** | **48** | **-402, -96** |
| 2010 Load | 1575 | 6714, -5617 |
| 2010X L-W-S | 1704 | 7219, -5986 |
| **Change** | **129** | **505, -37** |
| 2020 Load | 1977 | 8427,-7049 |
| 2020 L-W-S | 2019 | 8747,-7351 |
| **Change** | **42** | **321,-302** |

There is a substantial increase in the hourly schedule flexibility requirements between 2010 and 2020. The operational implications of the statistics presented in Table 14 through Table 16 will be examined in Section 6.2.

## 3.5. Hourly Forecast Error

A distinction of some importance is that between variability and uncertainty. The physical nature of both system loads and intermittent renewables is such that they vary. Much attention has been given in this report to quantify in the relative amount of change or variation in load and renewable power that can occur in different time frames. The ability of the power system to respond to changes is a function of the capability (physical and otherwise) of available resources to change output. One important aspect of this ability is knowledge, a priori, of the output requirement. Variability alone does not necessarily imply unpredictability. For example, tidal power, which typically varies from zero to maximum power twice a day is highly variable, but nearly perfectly predictable. The intermittent renewables under consideration in this study, solar and wind, are rather less perfectly predictable. In general, the more unpredictable the variation, the more agile the generating resources must be.

The variability of intermittent resources is reflected in delta statistics. The uncertainty of intermittent resources is reflected in forecast error statistics, which are examined in this section.

### *3.5.1. Day-Ahead Forecast Error*

Figure 43 shows day-ahead hourly actual and forecast data for an example 2010 summer week. The actual load (dark blue line) and forecast load (light blue line) curves are based on historical data scaled to the 2010 load level. The actual wind (red line) and forecast wind (orange line) were developed as described in the AWS report [7]. The actual solar (dark green line) was developed as described in Section 2.3. The forecast solar (light green line) was defined as the monthly average of the actual solar. The left y-axis scale applies to the load curves, and the right y-axis scale applies to the wind and solar curves.

The load actual largely follows the forecast, with some significant differences observed during the daily peak load period. Both under-forecasts (forecast less than actual) and over-forecasts (forecast more than actual) are observed. The solar actual follows the forecast as expected, given the forecast was derived from the actual. The wind actual has the same overall shape as the forecast, but the forecast is consistently less than the actual output.

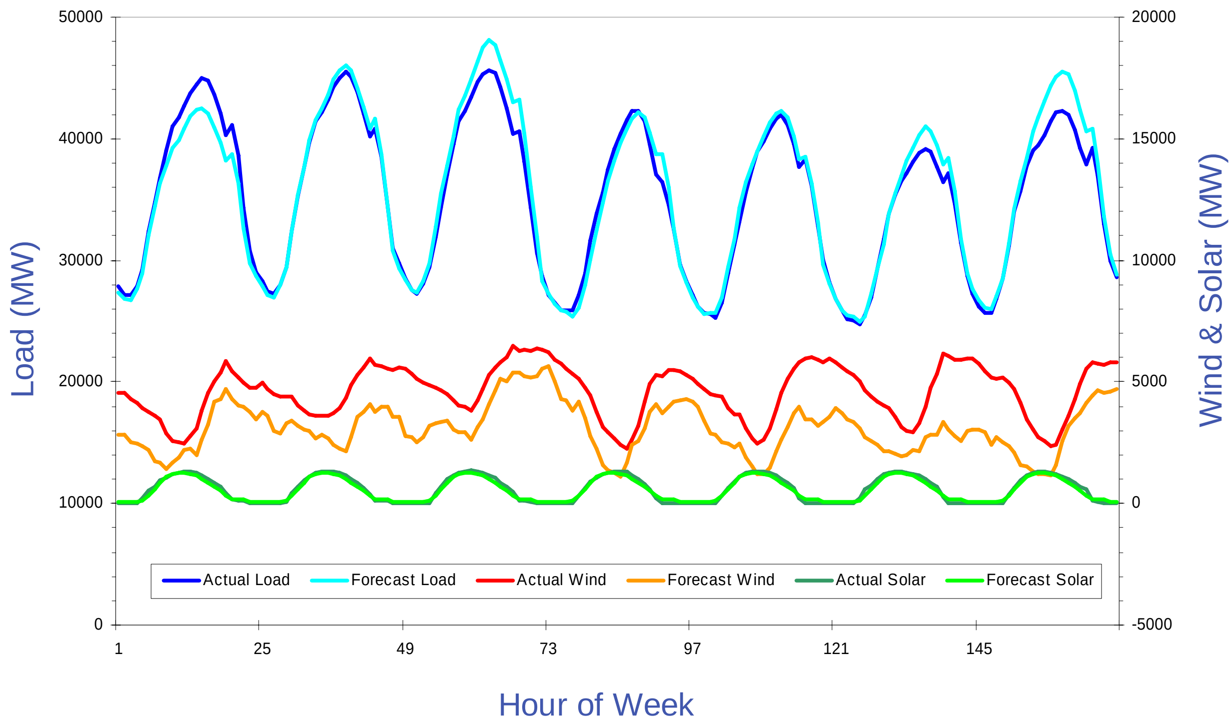


**Figure 43. 2010 Load, Wind, and Solar Forecasts and Actuals During an Example July Week.**

Figure 44 shows the day-ahead hourly forecast error curves for the same example week. Load forecast error (dark blue line) was calculated as forecast minus actual. The wind (orange line) and solar (green line) forecast errors were calculated as actual minus forecast. The net load forecast error is load forecast error minus wind forecast error minus solar forecast error. The load forecast error ranges between about +/- 3,000 MW. The wind forecast error ranges from about 0 MW to 3000 MW. This particular forecast includes a bias tends towards underproduction. In less flexible systems, such a bias can be a means of hedging underproduction risk. As will be shown later, under-forecasting has economic penalties, so subsequent results presented here are for nominally unbiased wind forecasts. The solar forecast error is within about +/- 200 MW.

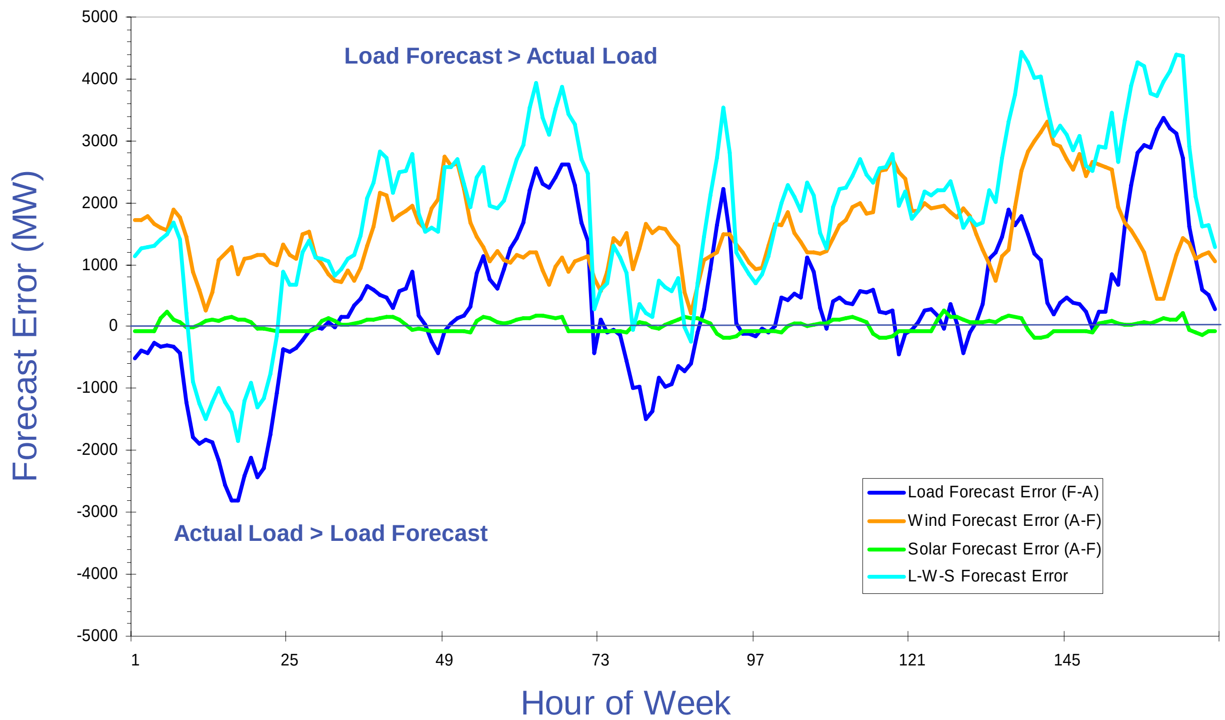


**Figure 44. 2010 Load, Wind, Solar, and Net Load Forecast Errors During Example July Week.**

Just as variability of intermittent resources is meaningful only in the context of existing load variability, so too, the uncertainty of intermittent resources is only meaningful in the context of existing load forecast error.

Figure 45 shows day-ahead forecast error duration curves for the 2010X scenario. The curves include load alone (dark blue line), net load (orange line), wind (green line) and solar (light blue line) day-ahead forecast errors. The uncertainty of wind forecast worsens the net load forecast.

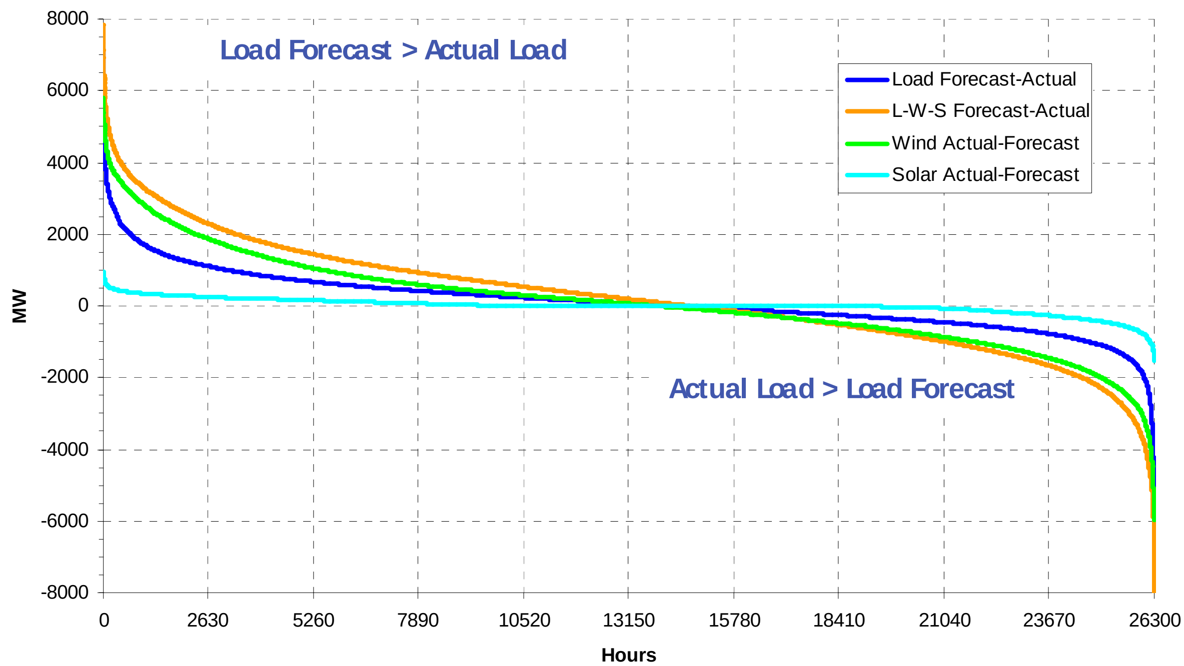


**Figure 45. 2010X Load, Wind, Solar, and Net Load Day–Ahead Forecast Error Duration Curves.**

Table 17 shows the 2006 hourly load forecast statistical results, grouped into ten deciles on the basis of load alone. The 10 percent of peak load hours are included in decile 1, and the 10 percent of light load hours are included in decile 10. The table shows the average, standard deviation, maximum, and minimum of the day-ahead hourly load forecast errors. Table 18 shows the 2006 hourly net load, wind and solar forecast statistical results, grouped into ten deciles on the basis of L-W-S. The first rows in the table show the average, standard deviation, maximum, and minimum of the day-ahead hourly net load (L-W-S) forecast errors. The next set of rows shows the average, standard deviation, maximum, and minimum of the day-ahead hourly wind forecast errors. The final set of rows shows the average, standard deviation, maximum, and minimum of the day-ahead hourly solar forecast errors.

**Table 17. 2006 Hourly Load Forecast Statistics (MW).**

| | Load Decile | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Trait** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **All Years** |
| **Average Error** | 157 | 313 | 141 | 178 | 147 | 93 | 36 | -2 | -24 | 59 | 110 |
| **σ Error** | 1318 | 1023 | 746 | 704 | 640 | 672 | 623 | 558 | 589 | 520 | 781 |
| **Maximum Error** | 5825 | 6533 | 4761 | 4813 | 3791 | 3585 | 4173 | 2531 | 3841 | 2208 | 6533 |
| **Minimum Error** | -6281 | -3896 | -3063 | -3400 | -3423 | -3589 | -2759 | -2778 | -1940 | -1675 | -6281 |

**Table 18. 2006 Hourly Net Load, Wind, and Solar Forecast Statistics (MW).**

| | Net Load Decile | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Net Load Trait** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **All Year** |
| **Average Error** | 231 | 448 | 247 | 301 | 276 | 261 | 202 | 185 | 142 | 269 | 256 |
| **σ Error** | 1339 | 1060 | 803 | 749 | 714 | 739 | 684 | 661 | 636 | 571 | 829 |
| **Maximum Error** | 6402 | 6555 | 4463 | 4519 | 3959 | 3397 | 4687 | 4974 | 3979 | 2321 | 6555 |
| **Minimum Error** | -6443 | -3954 | -3036 | -3205 | -3343 | -3556 | -2668 | -1773 | -1743 | -1701 | -6443 |
| **Average Wind Error** | -79 | -128 | -111 | -126 | -134 | -170 | -159 | -177 | -171 | -203 | -146 |
| **σ Wind Error** | 196 | 227 | 230 | 240 | 246 | 254 | 260 | 261 | 273 | 285 | 251 |
| **Maximum Wind Error** | 537 | 630 | 646 | 707 | 618 | 698 | 720 | 701 | 612 | 713 | 720 |
| **Minimum Wind Error** | -1104 | -1134 | -992 | -1083 | -1059 | -1079 | -1073 | -1079 | -1136 | -1137 | -1137 |
| **Average Solar Error** | -14 | -4 | -1 | 3 | 5 | 5 | 4 | 1 | 0 | -3 | -0.4 |
| **σ Solar Error** | 60 | 60 | 53 | 55 | 54 | 51 | 49 | 39 | 25 | 37 | 50 |
| **Maximum Solar Error** | 306 | 286 | 205 | 237 | 278 | 225 | 210 | 223 | 175 | 131 | 306 |
| **Minimum Solar Error** | -175 | -246 | -241 | -659 | -717 | -724 | -656 | -671 | -343 | -548 | -724 |

Table 19 shows the 2010 hourly load forecast statistical results, grouped into ten deciles on the basis of load alone. The table shows the average, standard deviation, maximum, and minimum of the day-ahead hourly load forecast errors. Table 20 shows the 2010T hourly net load, wind and solar forecast statistical results, grouped into ten deciles on the basis of net load (L-W-S). The first rows in the table show the average, standard deviation, maximum, and minimum of the day-ahead hourly net load forecast errors. The next set of rows shows the average, standard deviation, maximum, and minimum of the day-ahead hourly wind forecast errors. The final set of rows shows the average, standard deviation, maximum, and minimum of the day-ahead hourly solar forecast errors.

Table 21 shows the 2010X hourly net load, wind and solar forecast statistical results, grouped into ten deciles on the basis of net load (L-W-S). The format is the same as that used in Table 20.

**Table 19. 2010 Hourly Load Forecast Statistics (MW).**

| | Load Decile | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Trait** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **All Years** |
| **Average Error** | 172 | 344 | 154 | 196 | 162 | 102 | 39 | -2 | -26 | 65 | 121 |
| **σ Error** | 1445 | 1122 | 818 | 772 | 701 | 737 | 683 | 612 | 646 | 570 | 857 |
| **Maximum Error** | 6387 | 7164 | 5221 | 5278 | 4157 | 3932 | 4576 | 2776 | 4212 | 2422 | 7164 |
| **Minimum Error** | -6888 | -4272 | -3359 | -3729 | -3753 | -3935 | -3026 | -3046 | -2128 | -1836 | -6888 |

**Table 20. 2010T Hourly Net Load, Wind, and Solar Forecast Statistics (MW).**

| | Net Load Decile | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Net Load Trait** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **All Year** |
| **Average Error** | 246 | 611 | 544 | 585 | 758 | 846 | 721 | 639 | 799 | 1327 | 708 |
| **σ Error** | 1535 | 1356 | 1280 | 1246 | 1276 | 1366 | 1303 | 1249 | 1251 | 1174 | 1333 |
| **Maximum Error** | 7127 | 6978 | 7003 | 7059 | 6260 | 6996 | 7209 | 6954 | 7596 | 5106 | 7596 |
| **Minimum Error** | -7672 | -3690 | -3513 | -4144 | -4528 | -3921 | -4028 | -3741 | -3688 | -4065 | -7672 |
| **Average Wind Error** | -150 | -281 | -334 | -420 | -619 | -758 | -662 | -614 | -767 | -1265 | -587 |
| **σ Wind Error** | 646 | 765 | 806 | 895 | 993 | 1049 | 1031 | 1003 | 1035 | 1081 | 987 |
| **Maximum Wind Error** | 2705 | 2977 | 3132 | 3111 | 3330 | 3448 | 3579 | 2655 | 3612 | 3861 | 3861 |
| **Minimum Wind Error** | -2804 | -3467 | -3582 | -4152 | -4297 | -4508 | -4675 | -4181 | -4193 | -4249 | -4675 |
| **Average Solar Error** | -7 | -10 | -4 | -7 | 18 | 12 | 2 | 1 | 1 | -5 | 0 |
| **σ Solar Error** | 170 | 148 | 176 | 173 | 186 | 172 | 153 | 110 | 91 | 62 | 150 |
| **Maximum Solar Error** | 898 | 839 | 844 | 865 | 863 | 790 | 1000 | 925 | 880 | 638 | 1000 |
| **Minimum Solar Error** | -342 | -362 | -501 | -485 | -467 | -446 | -458 | -427 | -478 | -483 | -501 |

**Table 21. 2010X Hourly Net Load, Wind, and Solar Forecast Statistics (MW).**

| | Net Load Decile | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Net Load Trait** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **All Year** |
| **Average Error** | -383.9 | 14.7 | 5.9 | 103.3 | 227.1 | 297.8 | 278.8 | 213.2 | 419.5 | 1221 | 240 |
| **σ Error** | 1676 | 1450 | 1453 | 1500 | 1566 | 1681 | 1610 | 1635 | 1592 | 1542 | 1620 |
| **Maximum Error** | 6521 | 6311 | 5625 | 6141 | 7854 | 7148 | 7317 | 7081 | 6545 | 6920 | 7854 |
| **Minimum Error** | -9455 | -6160 | -5706 | -6618 | -5447 | -6695 | -6339 | -5021 | -6055 | -5653 | -9455 |
| **Average Wind Error** | 489 | 283 | 193 | 83 | -112 | -219 | -211 | -149 | -384 | -1166 | -119 |
| **σ Wind Error** | 945 | 1033 | 1080 | 1197 | 1295 | 1414 | 1393 | 1427 | 1411 | 1469 | 1350 |
| **Maximum Wind Error** | 5231 | 5221 | 4839 | 5581 | 5067 | 5497 | 5702 | 5095 | 5981 | 5786 | 5981 |
| **Minimum Wind Error** | -3324 | -4079 | -4300 | -4551 | -4931 | -5403 | -5143 | -5191 | -5170 | -5786 | -5786 |
| **Average Solar Error** | -26 | -15 | -3 | -11 | 30 | 19 | 5 | 1 | 8 | -8 | 0 |
| **σ Solar Error** | 268 | 248 | 257 | 255 | 266 | 246 | 208 | 173 | 153 | 127 | 226 |
| **Maximum Solar Error** | 1515 | 1271 | 1121 | 1249 | 1306 | 1180 | 1393 | 1285 | 1194 | 688 | 1515 |
| **Minimum Solar Error** | -796 | -824 | -948 | -940 | -731 | -652 | -641 | -661 | -738 | -710 | -948 |

Table 22 summarizes the standard deviation of the day-ahead load, net load and wind plus solar forecast errors under the 2010X scenario. The standard deviation of net load forecast error increases by 763 MW, or 90% , from the load alone forecast error standard deviation of 857 MW.

Table 23 shows the positive and negative energy associated with the day-ahead load, net load and wind plus solar forecast errors under the 2010X scenario. The load alone positive forecast error energy is about 9,600 GW-hr. The addition of wind and solar forecast errors results in a net load positive forecast error energy of about 19,500 GW-hr. The negative net load forecast error energy is also about twice the negative load alone forecast error energy.

**Table 22. 2010X Day-Ahead Forecast Error Standard Deviation.**

| | Standard Deviation (MW) |
|---|---|
| **Load (Forecast-Actual)** | 857 |
| **Wind+Solar (Actual-Forecast)** | 1566 |
| **L-W-S (Forecast-Actual)** | 1620 |

**Table 23. 2010X Day-Ahead Forecast Error Energy.**

| | Positive Energy (GW-hr) | Negative Energy (GW-hr) |
|---|---|---|
| **Load (Forecast-Actual)** | 9612 | -6442 |
| **Wind (Actual-Forecast)** | 14723 | -11583 |
| **Solar (Actual-Forecast)** | 1814 | -1814 |
| **L-W-S (Forecast-Actual)** | 19453 | -13142 |

Figure 46 shows another "open-high-low-close" stock chart with 2006 load and net load day-ahead forecast error scenario. The red bars represent the load scenario and the yellow bars represent the net load (L-W-S) scenario. The top of a bar represents the average value of hourly forecast error plus the standard deviation. The bottom of a bar represents the average value of hourly forecast error minus the standard deviation. The top of a vertical line represents the maximum hourly forecast error, and the bottom of a vertical line represents the minimum hourly forecast error.

The chart shows that wind and solar have some impact on forecast errors, including extremes, under all conditions. The standard deviation of the load alone variability for the 10th decile is 520 MW. This increases by 50 MW to 570 MW with wind and solar. Hence, under light load conditions, there is a 99.7% expectation (3σ) that hour-to-hour changes will be less than ±1560 MW with load alone, and ±1710 MW with the additional wind and solar.

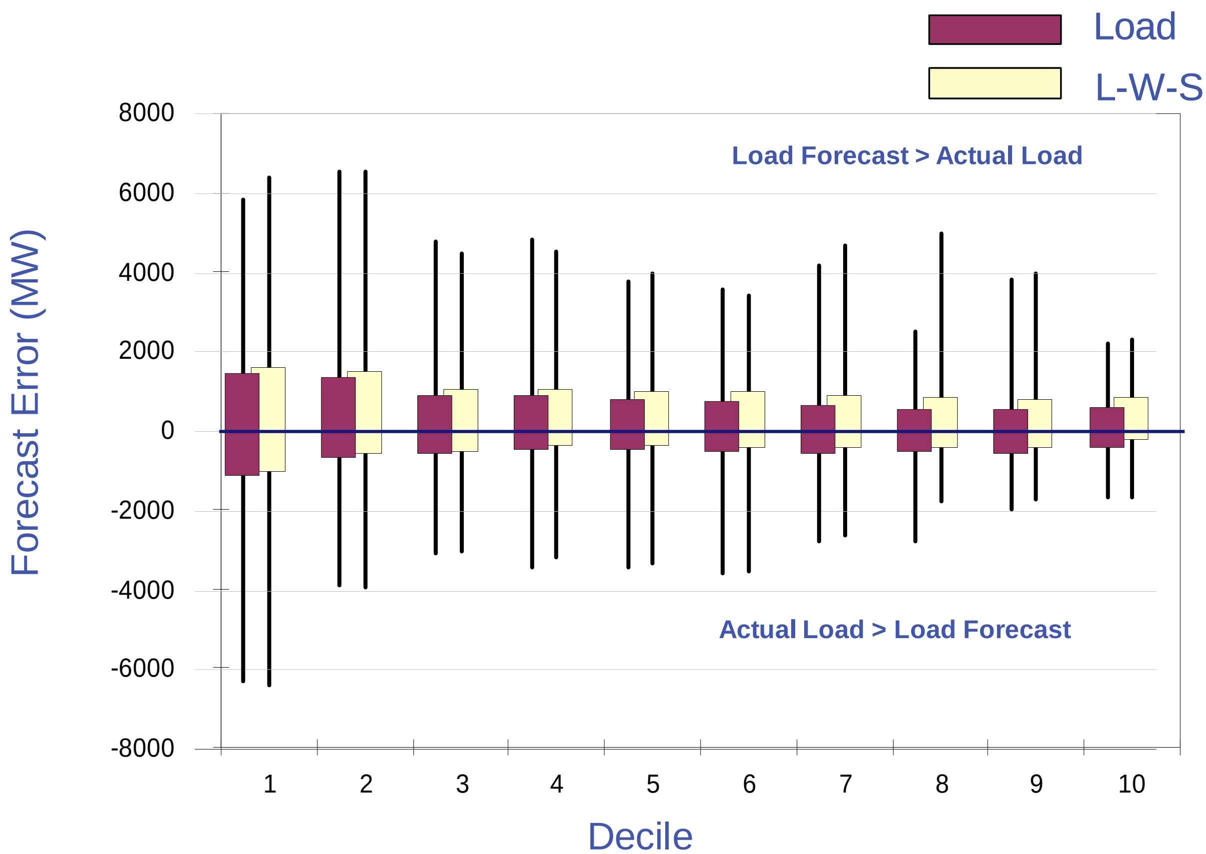


**Figure 46. 2006 Load and Net Load Day-Ahead Forecast Error Stock Chart by Decile.**

Figure 47 shows a similar "open-high-low-close" stock chart for the 2010X load and net load scenarios.

The chart shows that wind and solar have a significant impact on forecast errors, the including extremes. The overall uncertainty standard deviation ranges from 857 MW (2010 load alone) to 1,333 MW (2010T) to 1620 MW (2010X). The latter is approximately double the standard deviation for load alone. The energy error, as reported in Table 23, confirms this approximately two to one ratio. But at lighter load levels, and not just the lightest, the uncertainty is significantly higher. At the lightest load, 10th decile, the error increases from 570 MW (2010 load alone) to about double for 2010T (1174MW) and to almost triple for 2010X (1542 MW). The latter is an increase of 970 MW over the load alone standard deviation. Hence, there is a 99.7% expectation (3σ) that hour-to-hour changes will be less than ±1710 MW for load alone, increasing to ±3,522 MW for the expected 2010T scenario, and to ±4,620 MW for the extreme scenario. Under light load conditions, the largest positive load alone day-ahead hourly forecast error is about 2,420 MW. The largest positive net load day-ahead hourly forecast error is about 6,920 MW. The largest negative load alone day-ahead hourly forecast error is about -1840 MW. The largest negative net load day-ahead hourly forecast error is about –5,650 MW. The maximum and minimum light load forecast errors, for both the load alone and net load scenarios, slightly exceed the 3σ level. The worst load alone outliers are about +/-7,000 MW, and the worst net load outliers are about +/-7,700 MW. Under lighter load conditions (less than median) the difference is substantially larger. The load alone error roughly doubles from the +/-2,000-4,000 MW range to the +/-5,000-7,000 MW range. Overall, the system must be prepared for day-ahead uncertainty of about +/-5,000 MW.

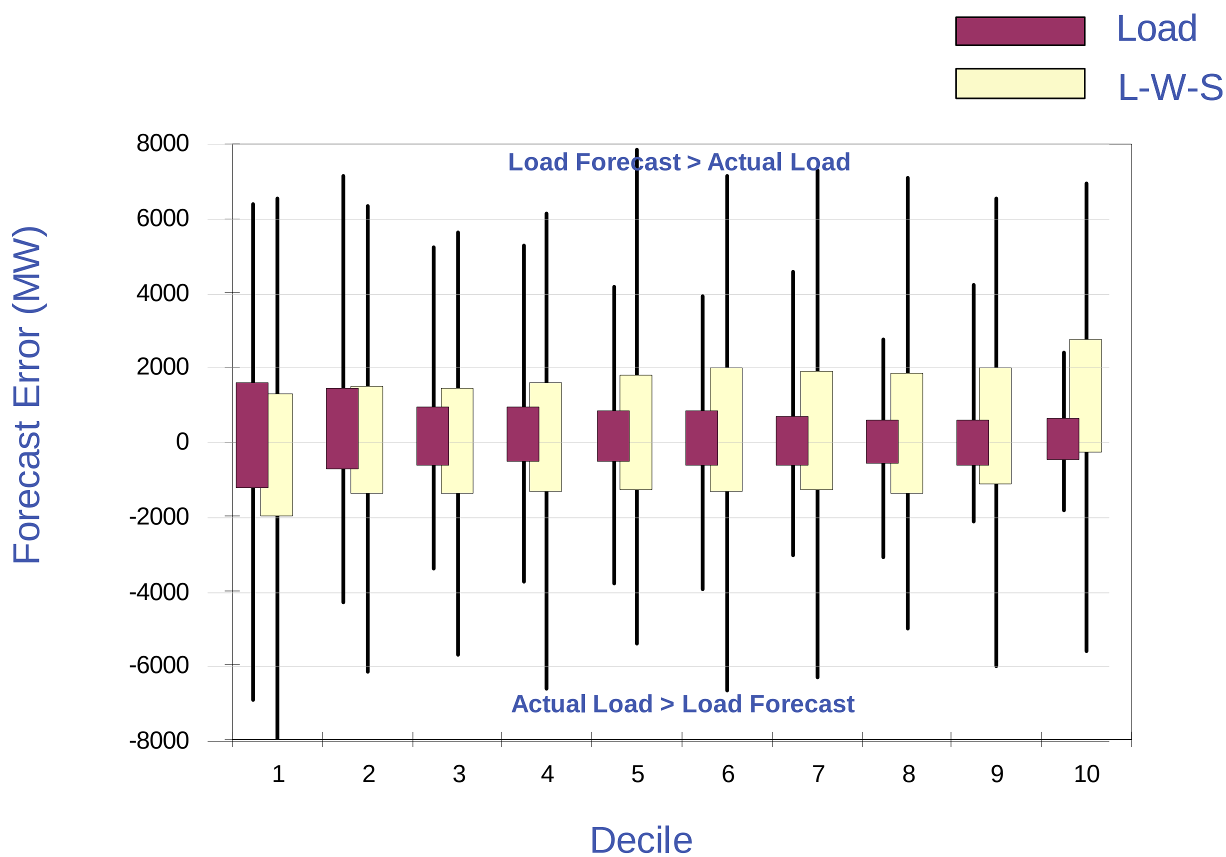


**Figure 47. 2010X Load and Net Load Day-Ahead Forecast Error Stock Chart by Decile.**

### *3.5.2. Hour-Ahead Forecast Error*

Figure 48 shows hour-ahead forecast error duration curves for the same 2010X scenario. The curves include the load alone (dark blue line), net load (orange line), wind (green line)and solar (light blue line) hour-ahead forecast errors. As expected, the uncertainty of the hour-ahead forecast is less than day-ahead forecast. However, the uncertainty of wind forecast still worsens the net load forecast.

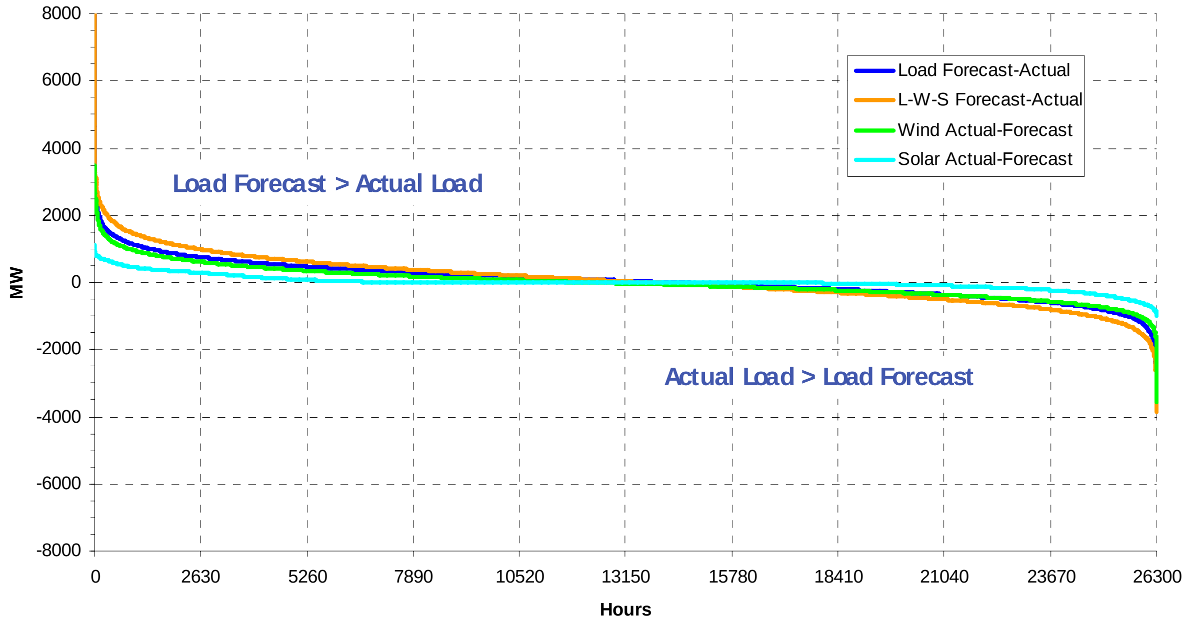


**Figure 48. 2010X Load, Wind, Solar, and Net Load Hour-Ahead Forecast Error Duration Curves.**

Table 24 summarizes the standard deviation of hour-ahead load alone, net load and wind plus solar forecast errors. The standard deviation of the net load forecast error is 156 MW, or 26%, larger than the load alone forecast error standard deviation of 606 MW.

Table 25 shows the positive and negative energy associated with the hour-ahead forecast errors. The positive energy of the net load hour-ahead forecast error is 2240 GW-hr, or 34%, larger than the positive load alone forecast error energy of about 6500 GW-hr. Similarly, the negative energy of the net load hour-ahead forecast error is -1700 GW-hr, or 36%, more than the negative load alone forecast error energy of -4800 GW-hr. Thus the impact of the intermittent renewables is much less in the hour-ahead forecast than in the day-ahead forecast.

**Table 24. 2010X Hour-Ahead Forecast Error Standard Deviation.**

| | Standard Deviation (MW) |
|---|---|
| Load (Forecast-Actual) | 606 |
| Wind+Solar (Actual-Forecast) | 706 |
| L-W-S (Forecast-Actual) | 762 |

**Table 25. 2010X Hour-Ahead Forecast Error Energy.**

| | Positive Energy (GW-hr) | Negative Energy (GW-hr) |
|---|---|---|
| Load (Forecast-Actual) | 6508 | -4810 |
| Wind (Actual-Forecast) | 4797 | -4796 |
| Solar (Actual-Forecast) | 1703 | -1703 |
| L-W-S (Forecast-Actual) | 8252 | -6553 |

Figure 49 shows another "open-high-low-close" stock chart of the load and net load hour-ahead forecast errors under the 2010X scenario. The chart shows that wind and solar have some impact on forecast errors, including extremes, under all conditions. Under light load conditions, the standard deviation of the load alone hour-ahead forecast error is 460 MW. This increases by 140 MW to 600 MW with the additional wind and solar. Hence, under light load conditions, there is a 99.7% expectation (3σ) that hour-to-hour changes will be less than ±1,380 MW for load alone, and ±1,800 MW for net load. Still under light load conditions, the largest positive hour-ahead load error is 3,160 MW. The corresponding net load error is about 2,200 MW. The largest negative hour-ahead load error under light load conditions is –1,600 MW. The corresponding net load error is about -2400 MW. Both the load and net load hour-ahead forecast error extremes are somewhat greater than 3σ.

Overall, the contribution of wind to hour ahead uncertainty is relatively much less than day-ahead. The hour ahead error with wind is only slightly worse across the board, consistent with the increase in sigma of about 20% (from about 600 to about 720 MW). Overall, the systems should plan for ±2,000 MW hour-ahead error.

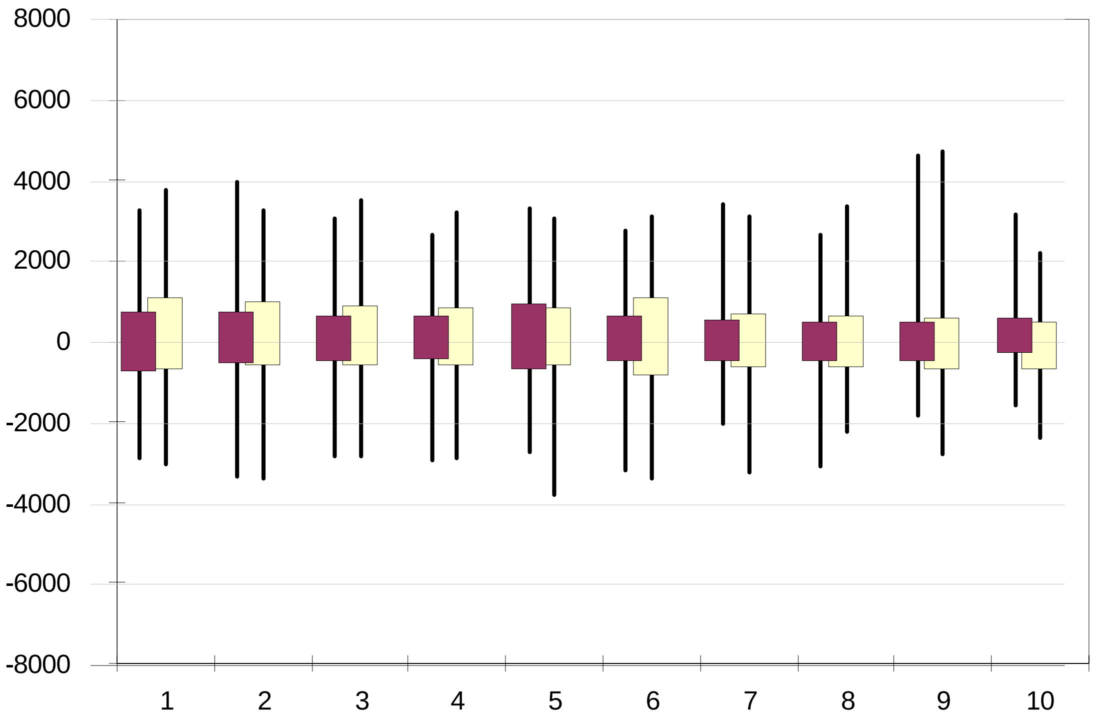


**Figure 49. 2010X Load and Net Load Hour-Ahead Forecast Error Stock Chart by Decile.**

## 3.6. Summary

The statistical results for the expected growth of renewables (2010T, 2020) are summarized as follows:

- Intermittent renewable generation changes daily and seasonally. Total statewide production of wind tends to be anti-coincident with load. Solar tends to be relatively coincident with load.
- Average wind penetration will range from about 4% at peak load up to about 20% at light load. Average solar penetration at peak load will grow to about 5%.

- Spatial variation in production between wind plants is substantial, and even wind plants in general geographic proximity, i.e. Tehachapi area, demonstrate significant diversity.
- Daily periods of rapid load rise and load decline will experience increased rates of change. Temporally coincident extreme changes in load and renewable generation are not expected. The most extreme sustained net changes, both up and down, are expected to be about 1,000 MW greater over 3 hours than that due to load alone.
- On average, variability due to intermittent renewables is about 3% to 7% larger than that due to load alone. The relative impact on hourly schedule flexibility and load following at light load will be greater. Incremental regulation requirements are relatively unaffected by load level.
- The day-ahead forecast error is about ± 5,000 MW, about half of which is due to intermittent renewables. The hour-ahead error drops to about ± 2,000 MW, to which intermittent renewables contribute about 20%.

The operational implications of the statistics presented here will be examined in Section 6.2.

# 4.0 Production Simulation Analysis

An economic simulation of the California system was performed to determine the operational impact of intermittent generation. Because California is such a significant portion of the WECC system it was necessary to model the interconnected operation of the entire WECC grid. The WECC was modeled broadly as six regions: Arizona, California, Canada, Northwest, Rocky Mountain and Mexico. These regions were further divided into 73 separate load areas, each with their own chronological load shape for the year. Loads within an area were then assigned to individual busses in the load flow. Over 2600 generating units were modeled within the WECC system. Thermal units were modeled with minimum operating points and multiple incremental cost segments as well as ramping and start-up considerations that mirror their physical capabilities. The unit commitment decision was based on information typically available in the day-ahead market, i.e. forecasted loads and forecasted wind and solar generation. Those units that were turned on were then dispatched in a "least cost" manner similar to the hour-ahead market. From this dispatch the hourly marginal prices, or spot prices as they are often referred to, were determined for each bus with averages calculated on an area, regional and system basis. Both the commitment and dispatch decisions recognized the individual bus locations of the generators and load and the transmission constraints present in the network. All transmission constraints in the WECC Path Rating Catalogue were considered. Conventional hydro generation was represented with a monthly minimum and maximum operating limit as well as a monthly energy availability. Within these constraints the hydro generation in California was scheduled on a local area basis at the times of highest load. Hydro in the rest of WECC was scheduled primarily on a regional basis with a few of the largest sites adjusting their schedules based on loads throughout the system. Various sensitivities were examined concerning the flexibility of the hydro generation. Pumped Storage Hydro, PSH, was also considered. The model recognizes the cost of energy available for pumping, the value of the energy when it is used for generation, the limits imposed by the storage reservoir and the overall cycle efficiency to determine the economic operation of the PSH units.

The system was examined for increasing levels of renewable generation, both intermittent (solar and wind) and constant (biomass and geothermal). The constant renewables were dispatchable but were assumed to bid in at a relatively low cost so that their output did not vary. The intermittent renewable generation was assumed to be a "price taker" and so was bid in at zero cost. The model was capable of shedding this energy if transmission constraints arose. The "cost savings" determined with the addition of the renewables is then a gross value of the energy and needs to be offset by the energy payments for the renewable energy as well as the capital costs of any system improvements required in order to determine the overall system economics.

The primary purpose of the simulation analysis was NOT to determine the economic value of the renewables but rather to determine the operational impact on the balance of the system. Does load shedding occur? What type of generation is displaced, coal or gas? What happens to transmission loading? What is the impact on emissions? What is the spot price impact of introducing a large amount of "price takers" to the system? What level of maneuverability is desired from the hydro generation? What is the ramping rate and range of the balance of the system? These are the types of results addressed in the remainder of this section.

The operational analysis was performed using the GE Multi Area Production Simulation program (MAPS). This program has been used for years throughout North America to assist planners, developers and regulators in the analysis of electric power systems. MAPS is a highly detailed model that calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. When the program was initially developed over thirty years ago, its primary use was as a generation and transmission planning tool to evaluate the impacts of transmission system constraints on the system production cost. In the current deregulated utility environment, the model has been useful in studying issues such as market power and the valuation of generating assets operating in a competitive environment. The unique modeling capabilities of MAPS include a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This enables the user to capture the economic penalties of redispatching the generation to satisfy transmission line flow limits and security constraints. The chronological nature of the hourly loads is modeled for all hours in the year. In the electrical representation, the loads are modeled by individual bus. In addition to the traditional production costing results, MAPS can provide information on the hourly spot prices at individual buses and flows on selected transmission lines for all hours in the year.

### *4.1.1. General Database Creation*

The MAPS master input file (MIF) was constructed specifically for the Intermittency Analysis Project (IAP). The MIF consisted of GE's Western Electricity Coordination Council (WECC) base inputs, California specific data and renewable generation information. The base MIF inputs covered the Western Interconnection, which is primarily comprised of the states west of the Rocky Mountains and portions of Canada and Mexico. Data for areas outside of California remained as originally conceived for the WECC for the IAP MAPS runs. The steps taken to create the final inputs are:

- Incorporating California data inputs developed by Rumla,
- Updating California generation units and fuel prices, and
- Integrating renewable generation development scenarios.

<u>California Specific Data</u>

MAPS inputs specific to California were extracted from a database developed over time by Rumla. The data incorporated 2003-2005 CEC and California ISO generation information. Updated elements included installation and retirement dates, California ISO reliability must-run (RMR) designations, and geothermal unit ratings. For thermal units, fuel type assignments and monthly prices were obtained from the CEC and implemented. A test MAPS run verified that the integration produced reasonable results.

Intermittency Analysis Project (IAP)

Updates performed for IAP units were made consistent with the MAPS California database reflecting 2005-2006 information. As in the initial California updates, changes in California ISO RMR designations, and CEC on-line unit status and fuel prices were implemented. Hydroelectric generation levels for each unit were adjusted to mirror historical monthly California hydroelectric generation from utility-owned units published by the CEC on its website.

Renewable Generation

Renewable generation additions consisted of biomass, geothermal, wind and solar units. IAP units were appointed identification labels and assigned to bus nodes. To the extent possible, IAP identification labels were matched to existing MAPS unit names. Any remaining unmatched IAP renewables were then inserted into the database. Wind and solar generation were modeled as hourly resources. For these two categories of renewables, existing California wind and solar units were removed from the database and the IAP data inserted. The total levels of renewable generation varied by scenario as described previously.

Fuel Price Assumptions

Generation was assumed to be committed and dispatched on a minimum cost basis. Historical heat rate data was used and the following fuel prices were assumed:

- Natural Gas ~ $5.70/MBTU
- Distillate Oil ~ $6.50/MBTU
- Coal ~ $1.5/MBTU

### 4.1.2. Scenario Description

The overall analysis examined the system operation for the 2006, 2010 and 2020 time frames. Because it can be difficult to compare results with a multiplicity of differences in the input, study cases were created with minimal changes between them. The various scenarios are described in Table 26. All scenarios use the same fuel prices. They also hold the generation mix, loads and transmission constant outside of California. The first three scenarios (based on 2010T) hold the transmission constant within California and only vary the level of renewable generation. The 2010X scenario further expands the level of renewables and also adds additional transmission within California to facilitate the additional generation. The final scenario, 2020, used the same generation and transmission mix as the 2010X case, but expanded the loads to reach the 2020 projected levels.

**Table 26. Production Simulation Scenario Description.**

| Scenario Title | Scenario Description |
|---|---|
| 2010T system – No new renewables | Geothermal, Biomass, Wind and Solar generation held at 2006 levels |
| 2010T system – No new intermittents | Geothermal and Biomass increased to 2010 projections but Wind and Solar held to 2006 levels |
| 2010T system – All renewables | Geothermal, Biomass, Wind and Solar generation increased to "2010T" projections |
| 2010X system | Wind and Solar further expanded to reach 33% Renewables |
| 2020 system | Similar to the 2010X system with the loads increased to 2020 values |

The advantage of these scenarios is that they allow the evaluation of different levels and types of renewable generation while the fuel cost and balance of the system remain constant. Each of these scenarios was created using either the 2002, 2003 or 2004 historical hourly load and wind profiles. The same is true for the concentrating solar plants. The 2004 photovoltaic (PV) shapes were applied for all cases.

## 4.2. Economics

The curve in Figure 50 shows a duration plot of the average California hourly spot price for the first scenario (2010T system – no new renewables) based on the 2002 load and wind shapes. This plot was created from the chronological hourly values that were then sorted to more easily see the impact of changes. This is a picture of the system costs before the addition of any renewable generation beyond the 2006 level. This will serve as a basis for comparison to the other scenarios. The costs were conservative in that "cost based" bids were assumed for all generation. Higher bids would only increase the value of the renewable generation.

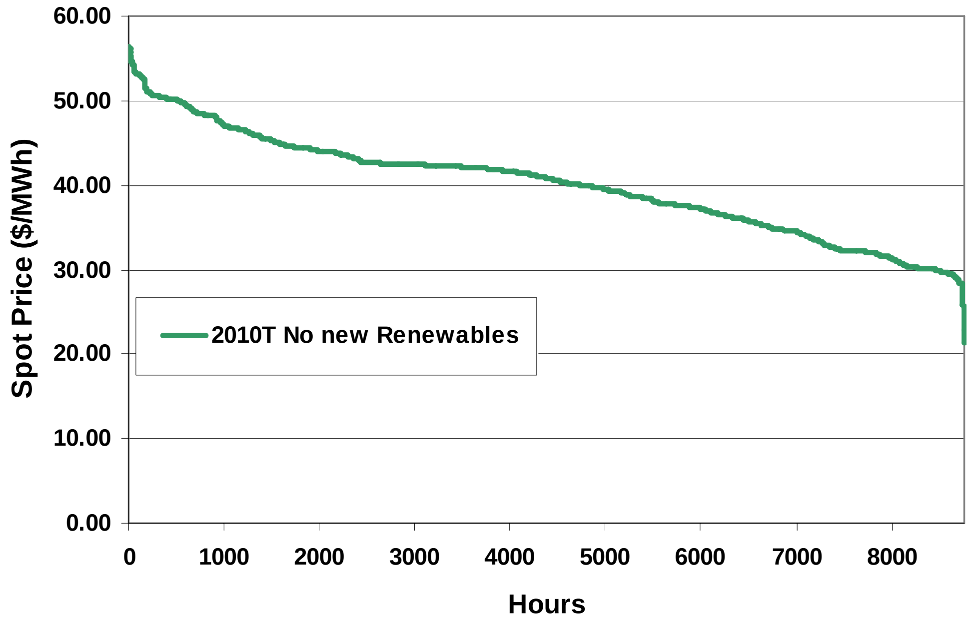


**Figure 50. Spot Price Duration Curve for 2002 Shapes (#1).**

In Figure 51 the new geothermal and biomass units are introduced into the system. These generators are dispatchable, but are assumed to have firm contracts and so are bid into the commitment and dispatch with low values. These cause the spot prices to decrease, but only slightly. The impact on spot prices is slight because this renewable energy is introduced into the system in a constant, predictable manner, which allows the remainder of the system to smoothly readjust in the commitment and dispatch.

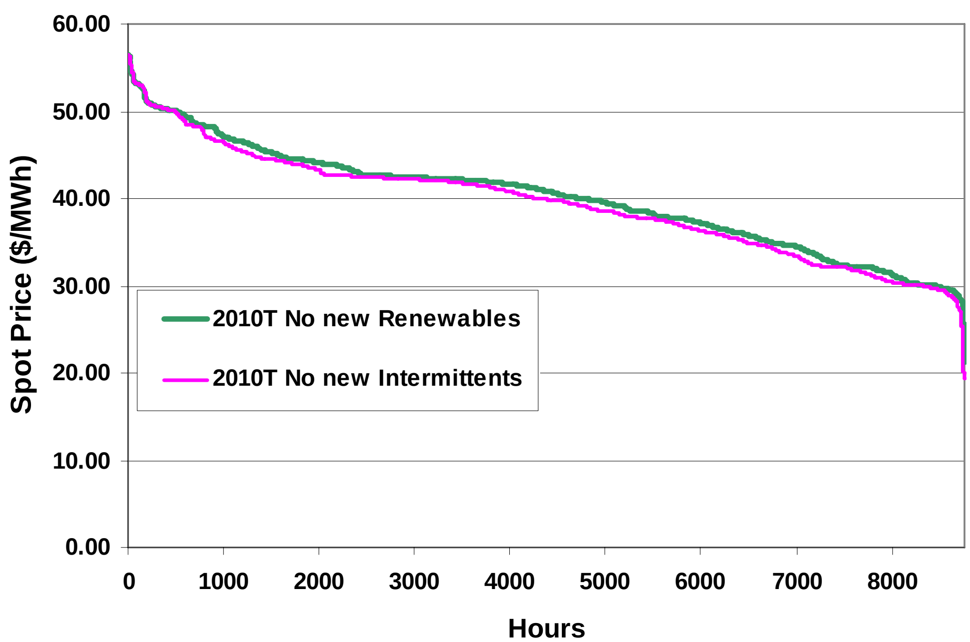


**Figure 51. Spot Price Duration Curve for 2002 Shapes (#2).**

Figure 52 now introduces significant amounts of new intermittent renewable generation. Two separate, chronological shapes were used to describe each wind plant over the course of the year. The first one applied is the actual wind generation based on the meteorological conditions that are present during the hour. This is what is injected into the system in the actual dispatch. The second shape used is the forecast of this hourly profile based on the expected meteorological conditions from roughly two days ahead of time. Both the intermittency and the error in forecast contribute to the variability introduced with the new curve. When wind is over-forecasted (i.e. forecast is higher than what actually occurs) then the existing committed generation must run more than was planned and possibly peaking generation needs to be called upon to supplement the other generation. Both of these factors will increase the spot prices. In other hours the wind is under-forecasted resulting in excess generation being on line that will cause a depression of the spot prices. Low prices can also result even when there is no forecast error. Increases in wind generation during low load nighttime hours can significantly lower the spot prices at a time when the balance of the system generation is unable (or unwilling) to back down. All of these impacts can be seen in the "2010T System" curve which includes all of the projected renewables for the base case.

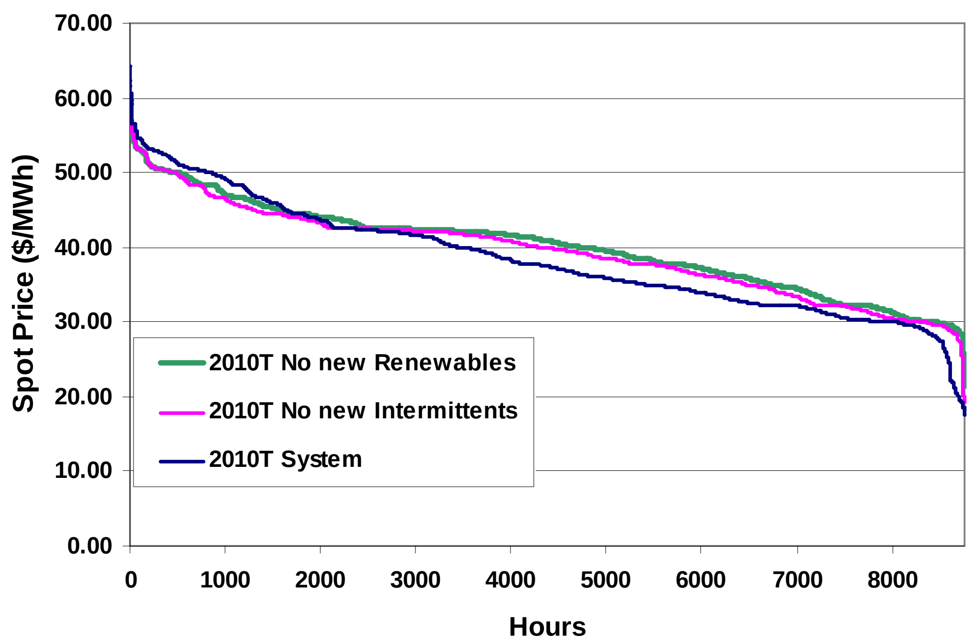


**Figure 52. Spot Price Duration Curve for 2002 Shapes (#3).**

These issues are amplified when the system is expanded to 33% renewables. Figure 53 adds the results of the 2010X scenario. Although there are no expectations that the renewables will reach this level by the 2010 time frame this analysis is intended to show the impact on a comparable scale of a high penetration of intermittent renewable generation.

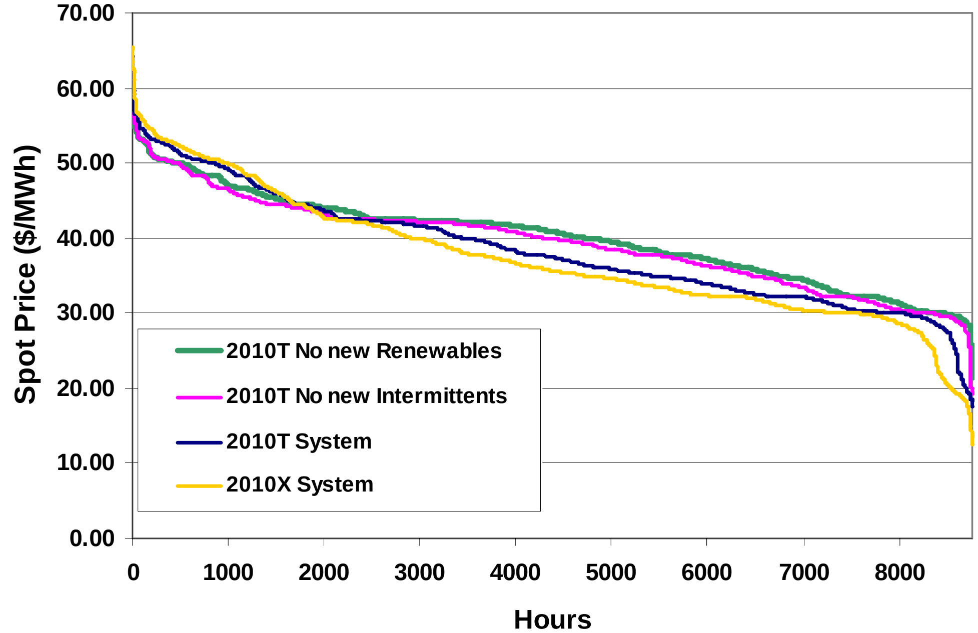


**Figure 53. Spot Price Duration Curve for 2002 Shapes (#4).**

The final curve in Figure 54 shows that as the load growth occurs the spot prices return to at or above the initial values and the drop off at the tail of the curve is significantly reduced.

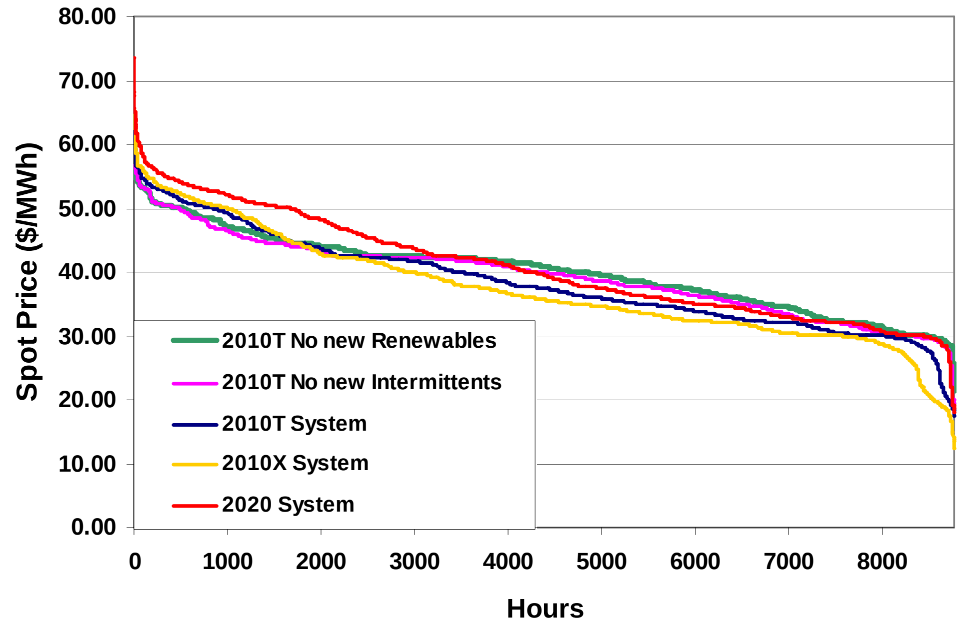


**Figure 54. Spot Price Duration Curve for 2002 Shapes (#5).**

Having demonstrated the "build" of the various scenarios for the 2002 shapes, Figure 55 and Figure 56 show similar results for the 2003 and 2004 profiles. Figure 57 expands the curve for the 2004 shapes to highlight the low spot price impacts. The sharp drop in spot prices indicate periods when the system is trying to shed all but the most critical resources. It is not necessary for the model to spill any hydro or actually dump any energy, but clearly it is starting to reach deeper into the stack of low cost generation. The addition of the geothermal and biomass generation expands the number of low priced hours from roughly 15 hours to about 75. The 20% renewable penetration in the 2010T scenario increases this to just over 300 hours. The 2010X case with 33% penetration is now up to about 750 hours that the wind energy will be of minimal economic value. The 2020 curve is back down to less than 100 hours in the tail.

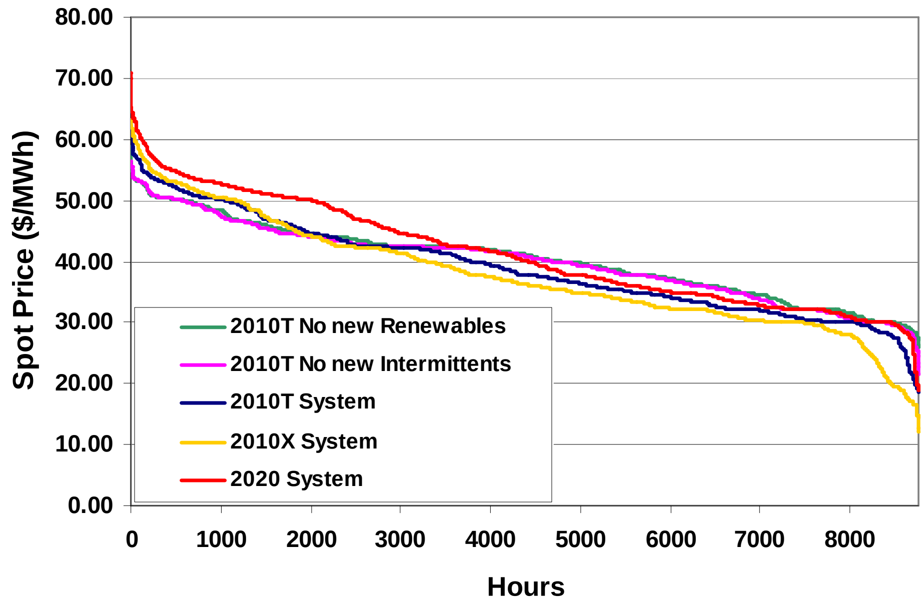


**Figure 55. Spot Price Duration Curve for 2003 Shapes.**

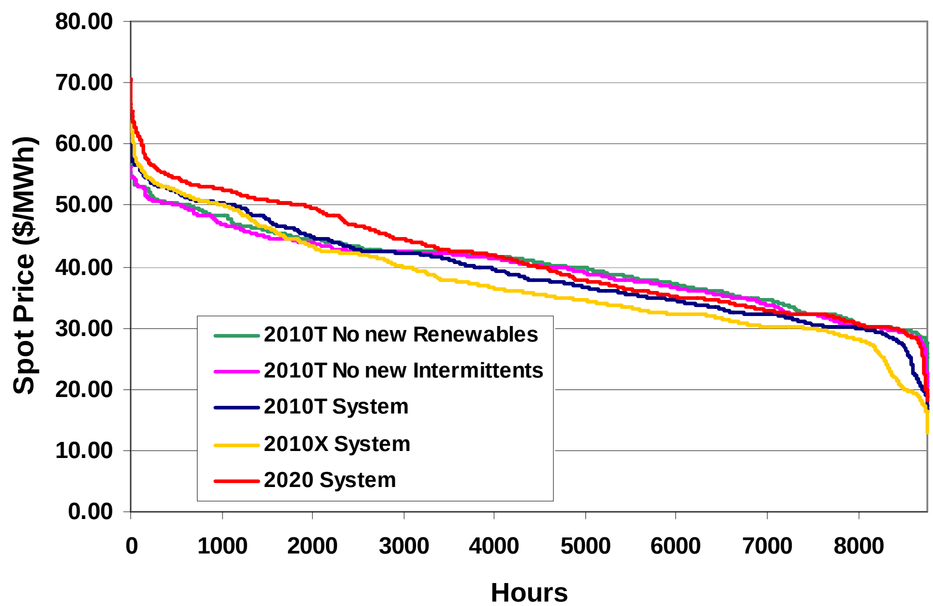


**Figure 56. Spot Price Duration Curve for 2004 Shapes.**

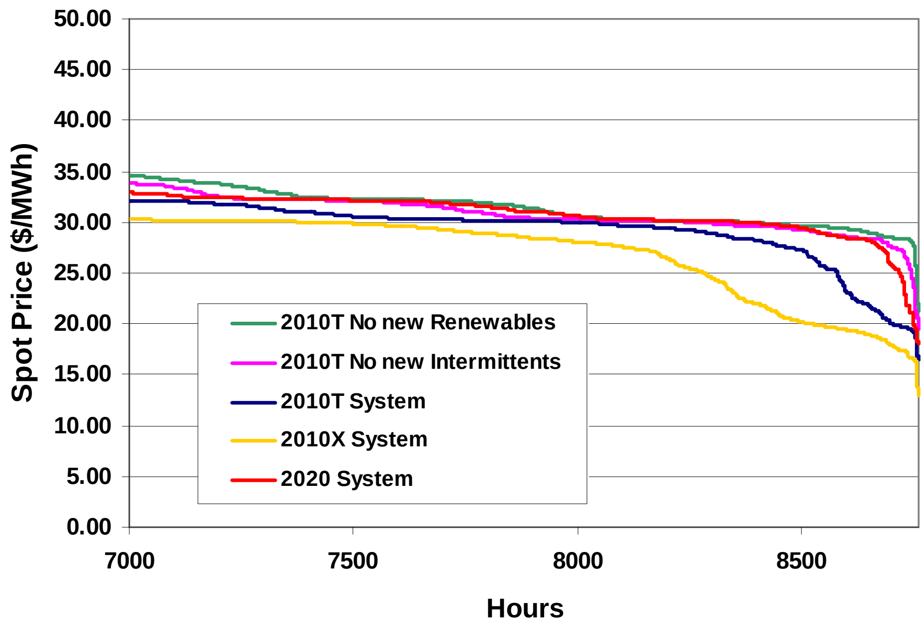


**Figure 57. Spot Price Duration Curve for 2004 Shapes (zoom).**

The reductions on overall WECC system variable operating costs are shown in Figure 58. It is important to note that this just represents the reduction in the cost of operating the balance of the system. This does not include the cost that needs to be paid for the renewable energy or for the capital expenditures required for the renewable generation and for the transmission enhancements required to support them.

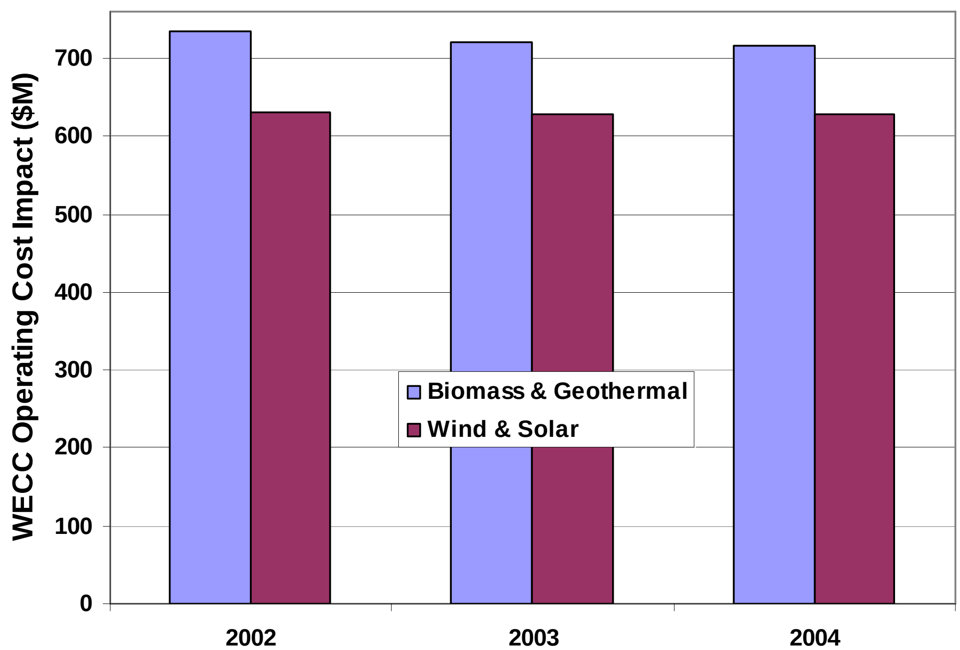


**Figure 58. WECC Operating Cost Reductions Due to Renewables ($M).**

The bars in Figure 59 show the same results expressed in $/MWh of renewable energy. The biomass and geothermal generation demonstrate about a $10/MWh higher value than the wind and solar energy. This is NOT an integration cost but simply a recognition that intermittent generation is not as valuable to the system as energy from a constant source.

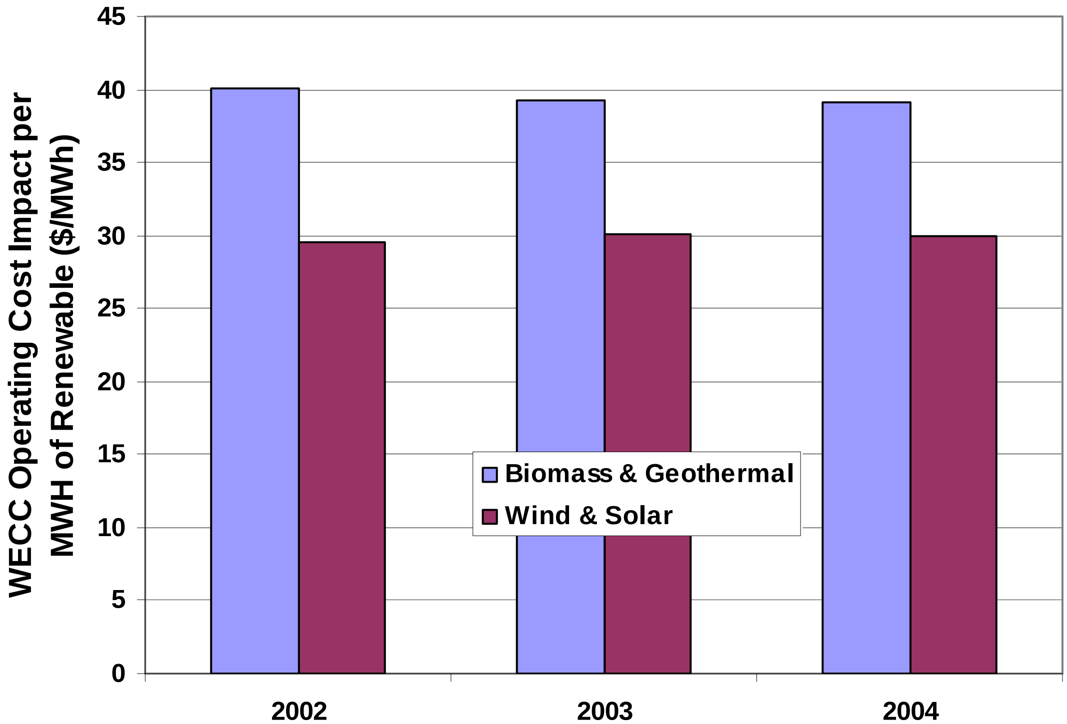


**Figure 59. WECC Operating Cost Reductions Due to Renewables ($/MWh).**

In a marginal cost market the load payments are equal to the hourly load times the hourly spot price for the load. The next two charts, Figure 60 and Figure 61, show the impacts on the load payments for both California and WECC expressed in both millions of dollars and in $/MWh of renewable energy. As with other factors being examined, the impact of additional renewable generation inside California extends well beyond the state's border.

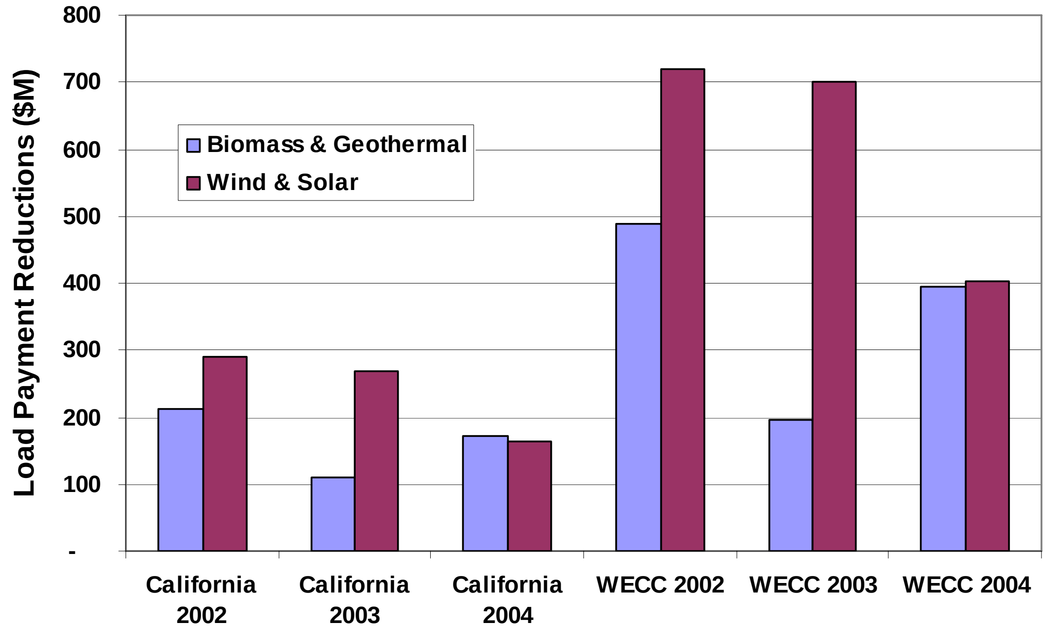


**Figure 60. Load Payment Reductions Due to Renewables ($M).**

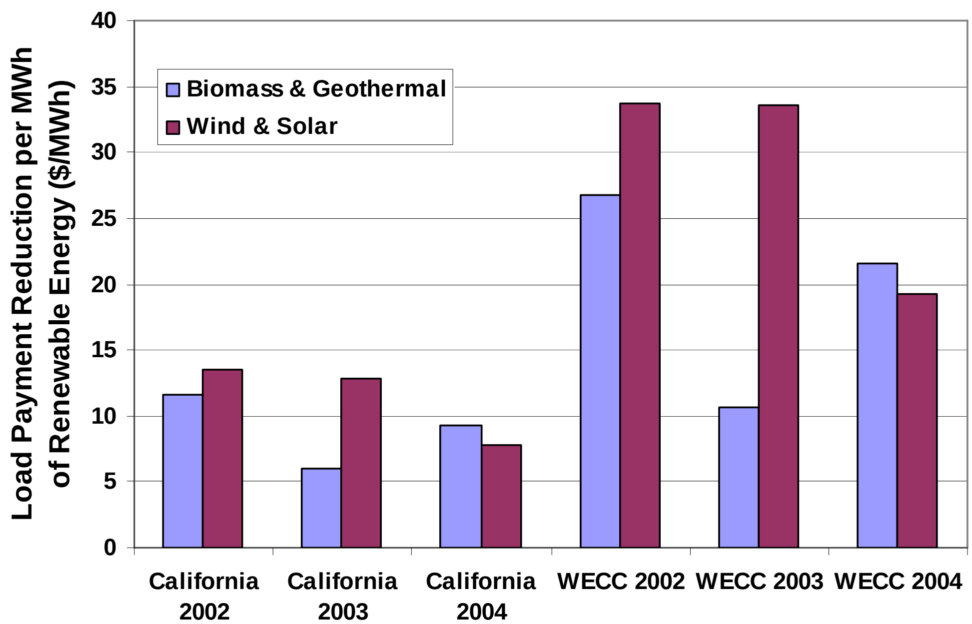


**Figure 61. Load Payment Reductions Due to Renewables ($/MWh).**

Figure 62 and Figure 63 show a similar impact on the generation revenue for all of the non-renewable generators in California and WECC. The revenue reduction has two components. First, the energy from the other generators has been reduced because it was displaced by the addition of the renewable generation. Second, the economic value of the generation that is still being produced has been reduced due to the introduction of large amounts of "price takers" into the generation bid stack. This adverse effect on other generation could possibly cause some existing marginally profitable generation to opt for early retirement or to cause some proposed additions to be postponed. It is important for sufficient incentives, such as the capacity market, to be in place to ensure that reliability does not suffer.

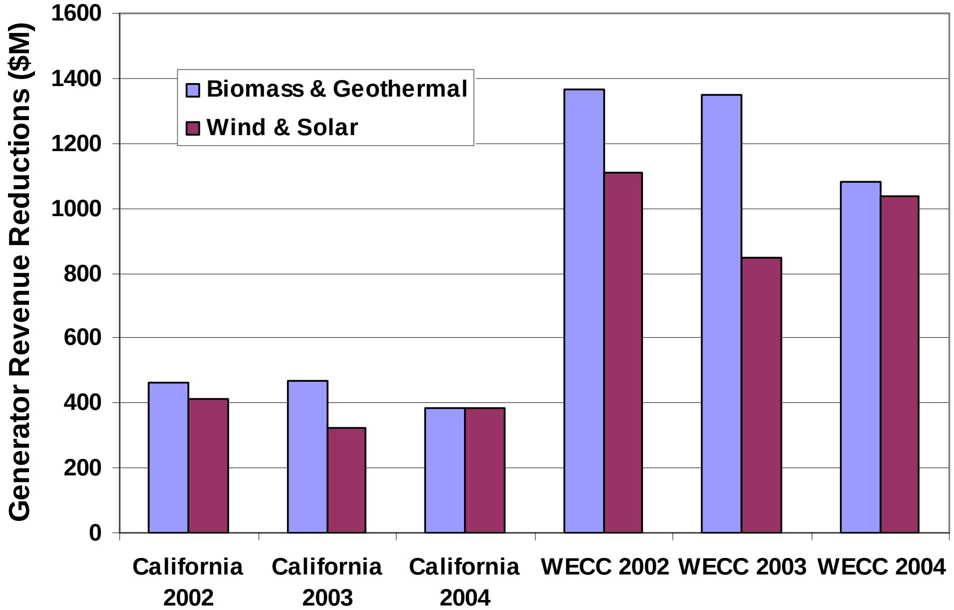


**Figure 62. Non-Renewable Generator Revenue Reductions Due to Renewables ($M).**

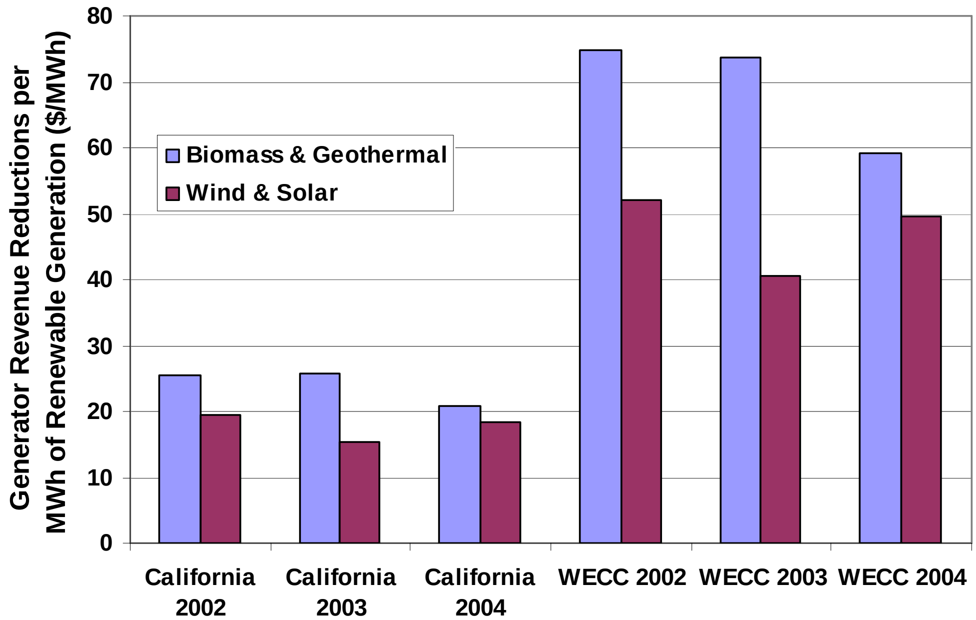


**Figure 63. Non-Renewable Generator Revenue Reductions Due to Renewables ($/MWh).**

## 4.3. Intermittent Renewable Forecasting

The impact of forecasting for intermittent renewable generation is of sufficient importance to merit a separate section. Historically, forecasting of intermittent energy was often ignored. This was perfectly adequate for systems with installed wind generation less than 0.1% of peak load.

The variability of the wind generation was lost in the variability of the load and could easily be absorbed in the dispatch "when and if it showed up". As the energy contribution from intermittent units expands to 5%, 10%, 20% and even in excess of 30% this is no longer possible. The basic assumption used in this analysis was that hydro operation and thermal unit commitment would be adjusted (to the extent possible) based on the projected wind and solar generation, which was determined from the forecasted meteorological conditions from roughly two days in advance of the actual occurrence. "State of the art" forecasting was assumed and hourly profiles were developed as described elsewhere in this report. Sensitivity analyses were performed to examine the impact of either "perfect forecasting", (forecast equals actual generation that occurs) or of ignoring the forecast and simply allowing the intermittent energy to just show up in the hour ahead market.

Figure 64 shows the impact of the forecast on the California average system spot prices for the 2010T scenario. The green curve, based on estimated forecasts, is the one that has been shown in Figure 50. The red curve shows the effect of a perfect forecast for the intermittent energy. The higher spot prices are reduced because the system is no longer "over-forecasting" and requiring peaking units to make up the shortages. Similarly, the lower spot prices are increased due to the elimination of "under-forecasting". Significantly, the number of hours with a sharp drop in spot price have been reduced. The blue curve, where intermittents are ignored in the commitment, shows the other extreme. Spot prices are severely depressed throughout the year due to the constant over commitment of resources and the number of hours with a sharp drop in prices has more than doubled. While some may think "spot price reductions are good, right?" this severe drop could have adverse effects on the stability of the overall market. Combining the hourly spot price with the load would show that the load payments and the corresponding generator revenues would decrease by billions of dollars. This significant drop in generator revenues could cause generation to leave the system, causing a reduction in overall system reliability.

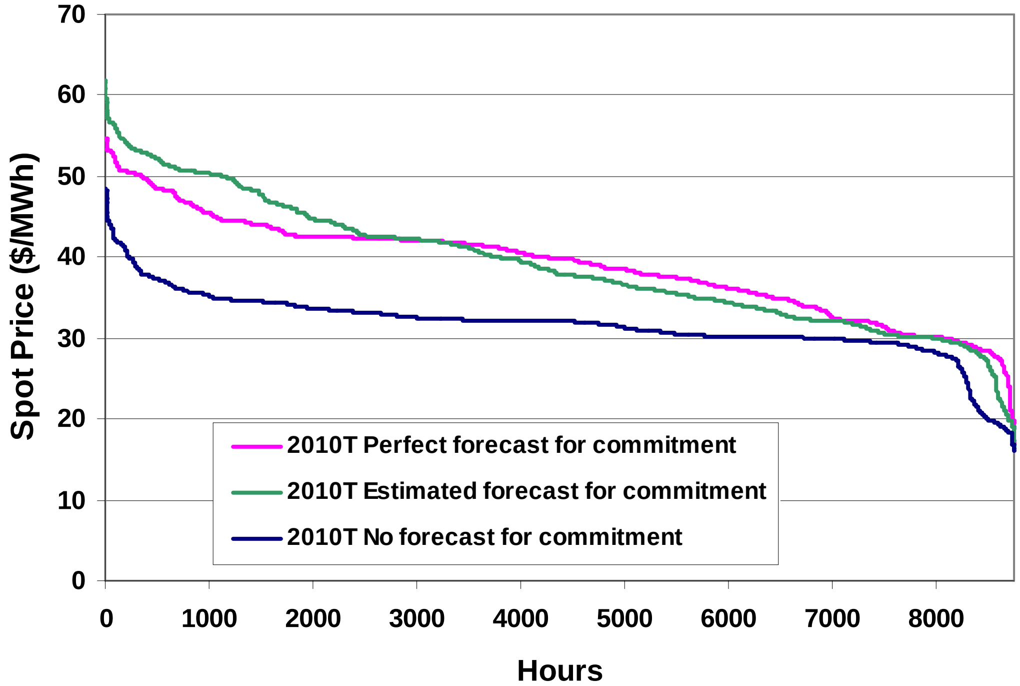


**Figure 64. Impact of Intermittent Forecast on Spot Price (2010T).**

The curves in Figure 65 show that the impact is even more pronounced in the 2010X scenario with 33% renewable generation, as would be expected. Figure 66 shows that as the loads are increased to the 2020 levels the spot prices increase to higher levels.

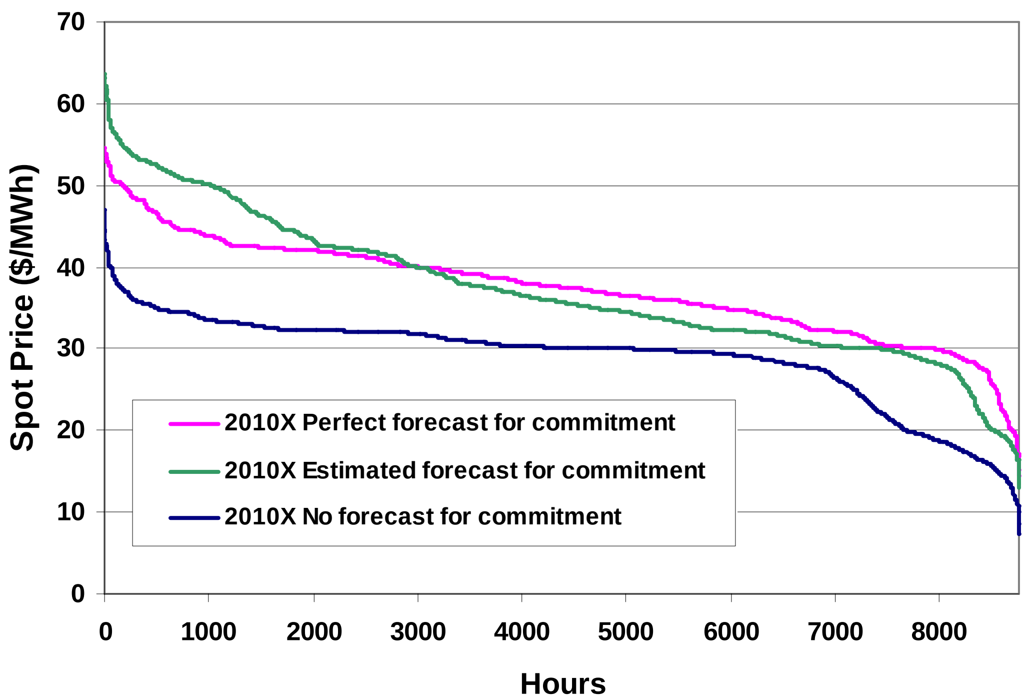


**Figure 65. Impact of Intermittent Forecast on Spot Price (2010X).**

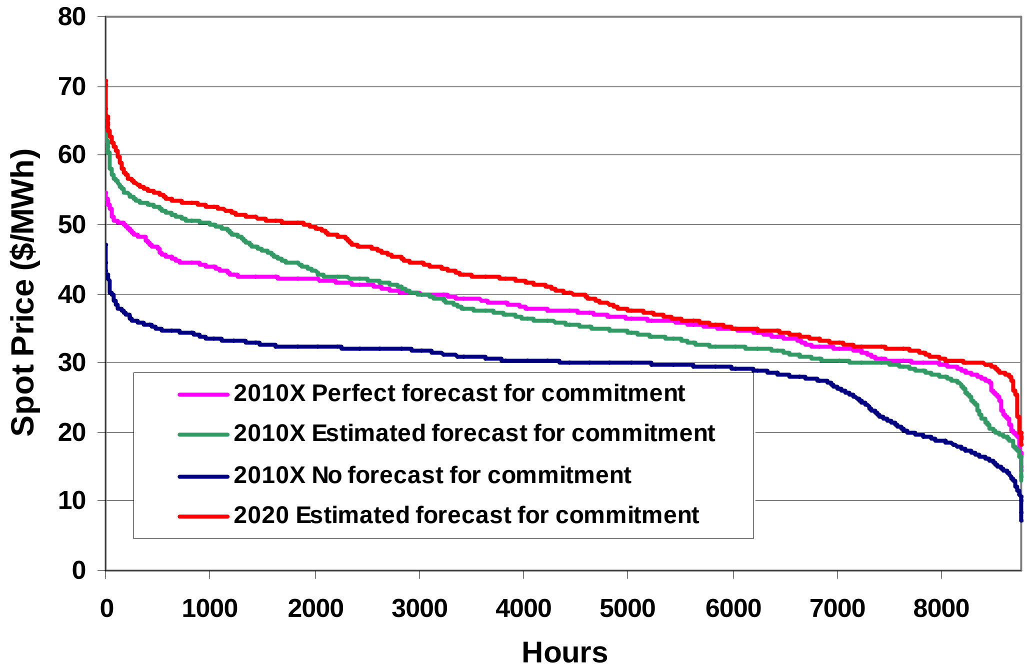


**Figure 66. Impact of Intermittent Forecast on Spot Price (2010X and 2020).**

The changes in the system variable costs of operation are demonstrated in Figure 67. This chart shows that there is significant value in implementing state-of-the-art estimating techniques across the system. And that there is still additional value that can be gained by improving the existing methodologies. When divided by the intermittent energy the estimated forecast has a benefit of $4.37/MWh and the perfect forecast could add an additional $.95/MWh. As discussed before, ignoring the wind in the day ahead commitment can result in serious over commitment of thermal generation. Even if the forecast error is 20%, a 5,000 MW forecast would result in actual generation in the range of 4,000 MW to 6,000 MW. It is far better to be over or under committed by 1,000 MW than to be always over committed by the entire 4,000 MW to 6,000 MW. The current direction of the  California ISO to forecast of all intermittent generation on the California grid is critical. Supporting and enhancing the system capabilities in this area are in the best interest of the overall system.

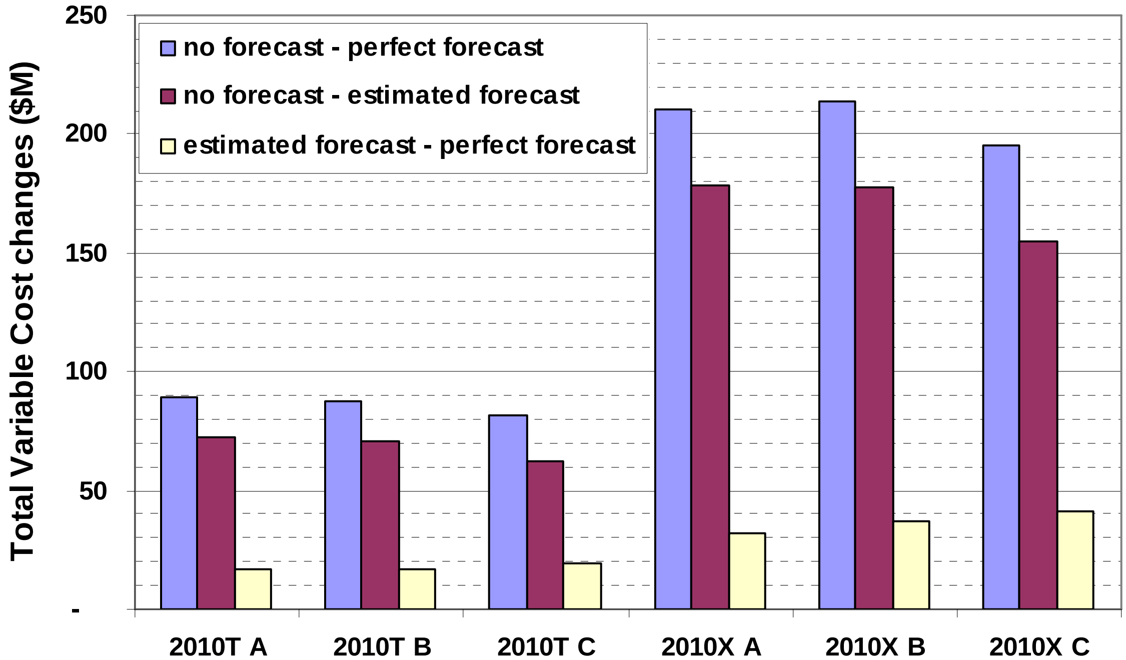


**Figure 67. Total Operating Cost Impact of Intermittent Forecasting.**

Figure 68 and Figure 69 show the generator revenue reductions by generator type for both California and WECC respectively. The first column shows the impact of non-intermittent renewable generation (biomass and geothermal) and the second column shows the impact of the intermittent generation (wind and solar). This assumed an estimated forecast for the intermittent generation. The bulk of the impact is on the combined cycle units. Later sections will show that these are the units that are largely displaced by the renewable generation. The revenue reductions on other generation types were due largely or completely to the reduction in spot prices. The third column shows the incremental revenue reductions due to ignoring the intermittent generation in the commitment. Although the impact on combined cycle units is increased slightly it is largely the hydro, nuclear and steam generation that is impacted most. Although little or no energy is displaced, the spot price impacts on their revenue is significant due to the amount of energy produced. This underscores the fact that if intermittent generation is being added to the system it is in the interest of all of the generation to use the best intermittent forecast possible.

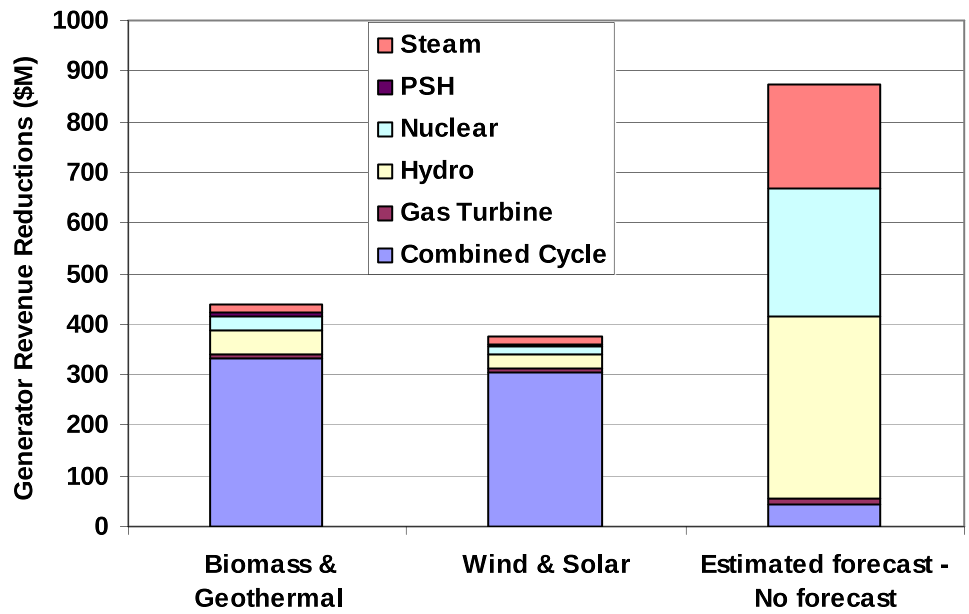


Figure 68. California Generator Revenue Reductions by Type (2010T).

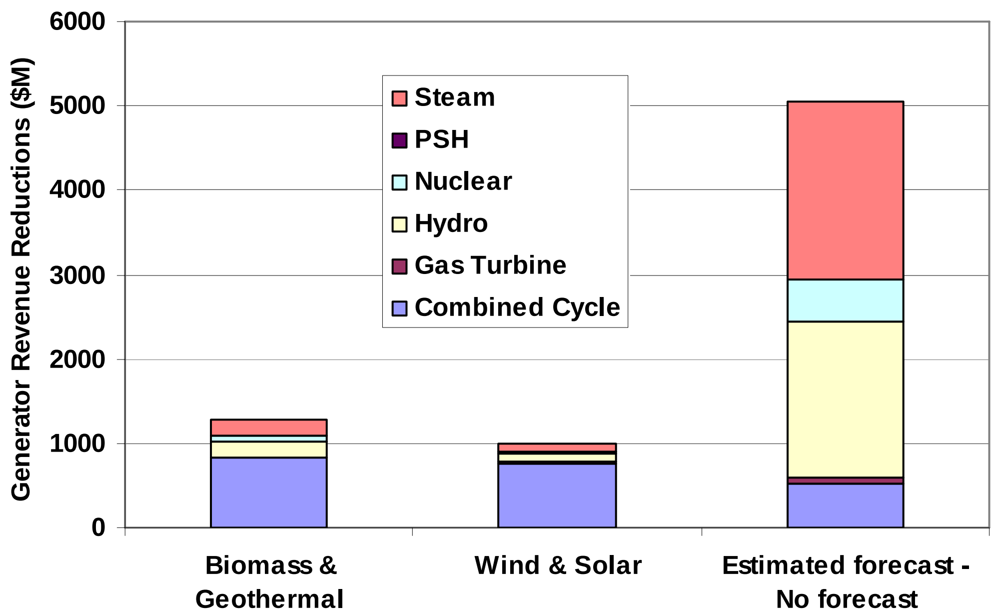


Figure 69. WECC Generator Revenue Reductions by Type (2010T).

## 4.4. Operations

This section looks at the overall operational impact of the addition of renewable generation and less at the economic side. Figure 70 shows that virtually all of the energy displaced inside California will come from combined cycle units and that roughly 60% of all of the renewable energy will be absorbed by reductions in the imports from outside the state.

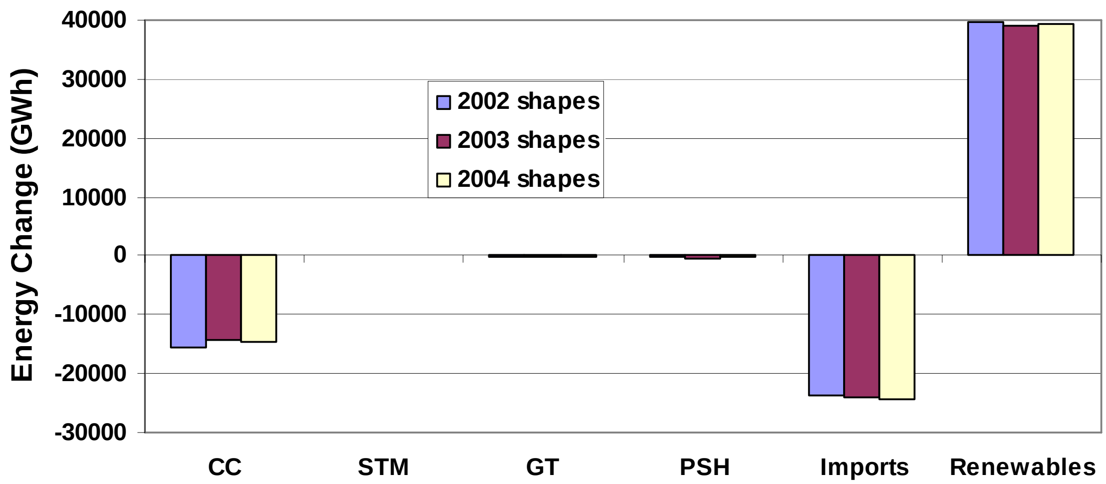


**Figure 70. California Energy Change Due to Renewables (2010T).**

Looking at the situation from the WECC perspective in Figure 71 shows that the displaced California imports are almost all from combined cycle units outside the state.

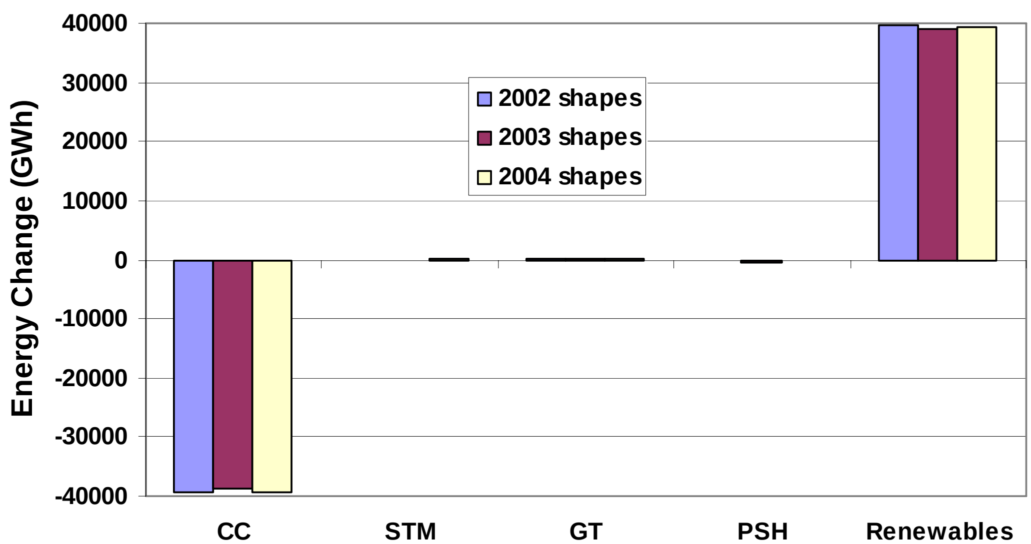


**Figure 71. WECC Energy Change Due to Renewables (2010T).**

These curves are not to imply that a large portion of the regulation and load following burden of an aggressive California renewable energy expansion will be foisted upon their neighbors. These are scheduled reductions in the roughly 10,000 MW of imports that routinely cross the California borders. Most of the reductions would be expected to take place in the day ahead market with slight adjustments to imports in the hour ahead market due to changes in the intermittent energy forecasts in much the same way that changes are made now due to fluctuations in the load forecast. Intra-hour variations in the intermittent generation would be accommodated by in-state generation. Due to the relatively high level of imports currently coming into California, it is only natural to expect that the addition of any new generation source within California would result in a reduction in these imports.

The curves in Figure 72 show changes in the California renewable generation for the various scenarios. The lowest curve represents the existing level of both intermittent and non-intermittent generation within the state. The next curve up represents the addition of new geothermal and biomass generation. As can be seen, the first two curves are roughly equidistant for the entire year since the new non-intermittent generation is fairly constant for the year. The third curve shows the addition of the new wind and solar generation in the 2010T scenario. The final curve represents the 2010X scenario penetrations. Figure 73 shows just the wind and solar values for the same scenarios. Note that even in the extreme scenario (2010X) the total intermittent generation is less than 4,000 MW for over half of the year.

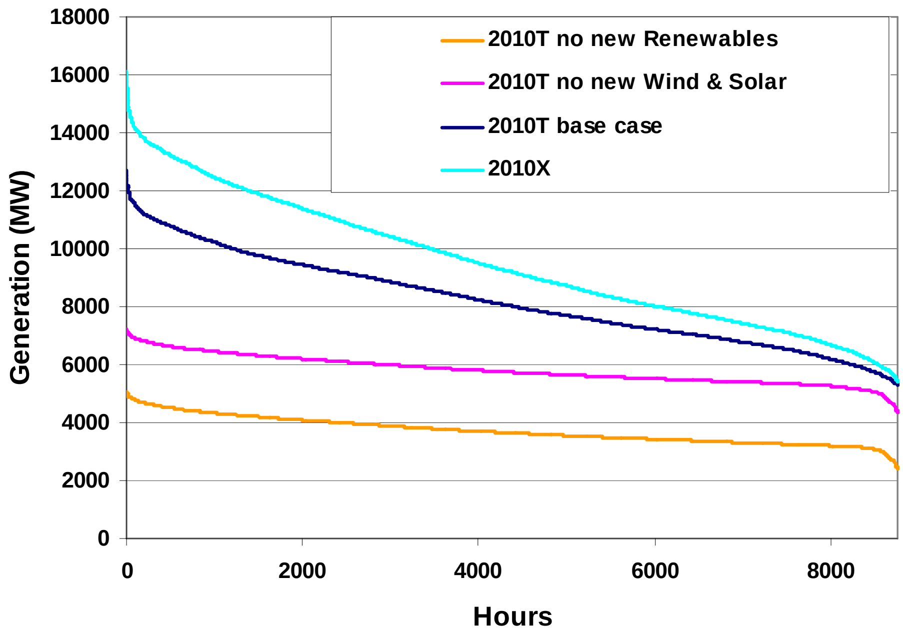


**Figure 72. Annual Duration Curves – California Renewable Generation.**

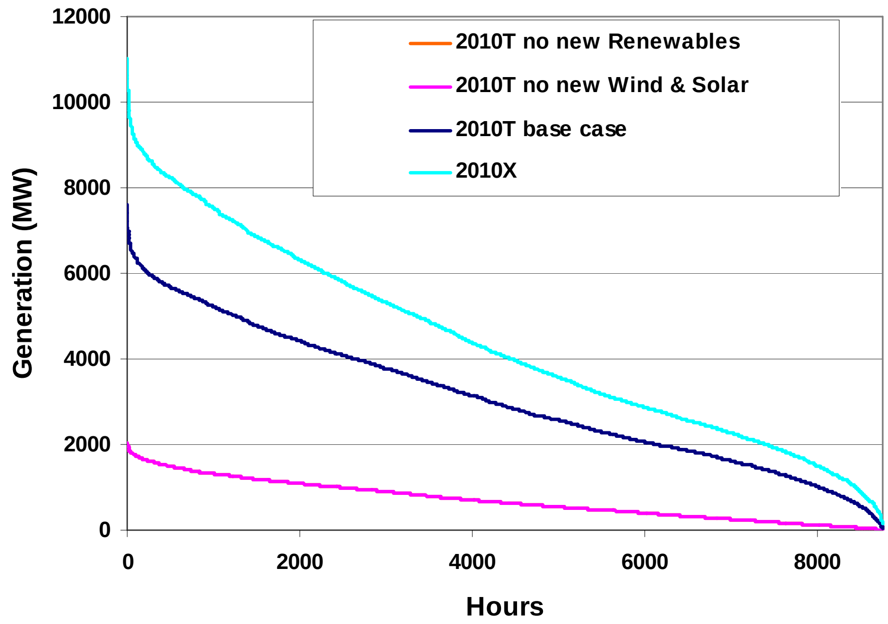


**Figure 73. Annual Duration Curves – California Wind and Solar Generation.**

The sets of curves in Figure 74 show the annual duration curves for the generation from California nuclear, steam and gas turbine units. As can be seen, there is not much change in their overall output.

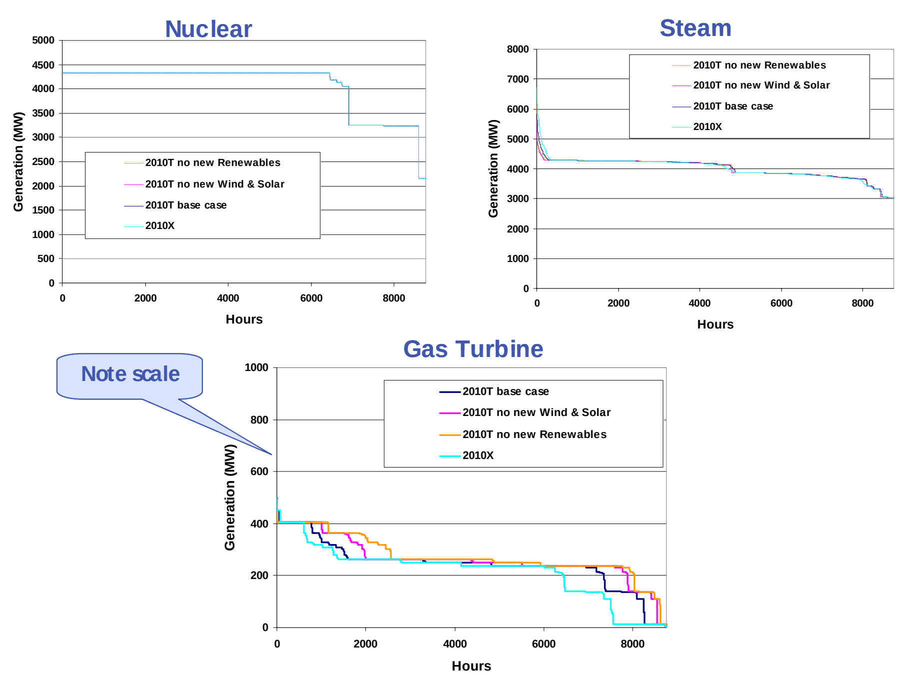


**Figure 74. Annual Duration Curves – California Nuclear, Steam, and Gas Turbines.**

The curves in Figure 75 show the annual generation from the California hydro generation. This was initially quite surprising because it seemed to indicate that not much changed in the hydro operation when the renewable generation was added. Although the geothermal and biomass energy is produced in a fairly constant manner which would not be expected to impact the hydro, the intermittent nature of the wind and solar was expected to cause changes.

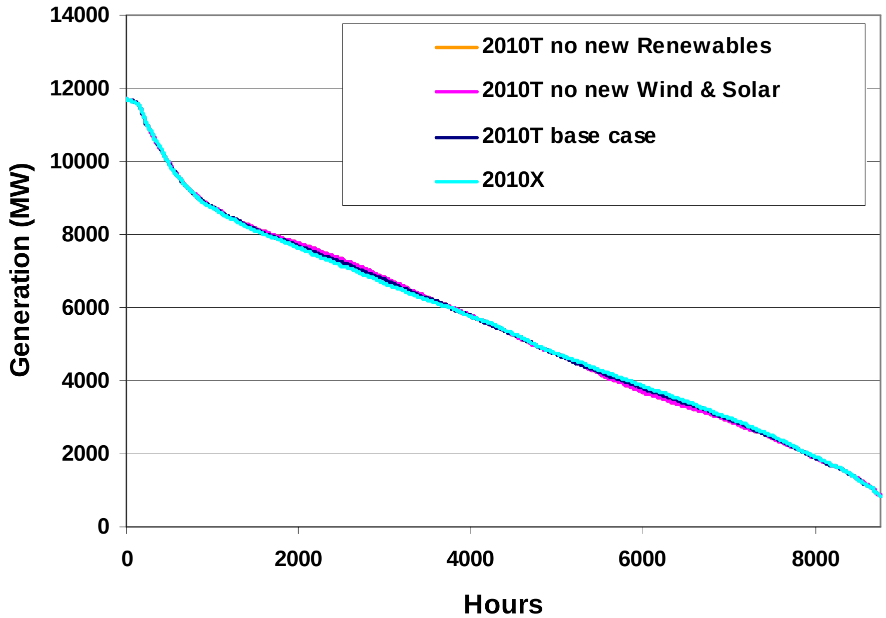


**Figure 75. Annual Duration Curves – California Hydro Generation.**

The curves in Figure 76 show the operation of the California hydro generation for one week from the simulations with and without the new wind and solar generation. It can be seen here that the hourly hydro generation did shift, although the total generation for the week remained approximately constant. Figure 77 plots this delta operation for the entire year. The smooth yellow curve superimposed over the other is the chronological deltas sorted from high to low for the year. From this curve it can be seen that the shift in the hydro generation is generally less than +/- 1,500 MW over the course of the year. The shift in operation only exceed +/- 1,000 MW for roughly 300 hours of the year and was less than +/- 500 MW almost 85% of the time. This was for the addition of almost 7,000 MW of new intermittent generation. Even the expansion to the 2010X scenario only broadened the shoulders of the curve slightly. Later in this section we will examine the ability of the hydro to accept this much change.

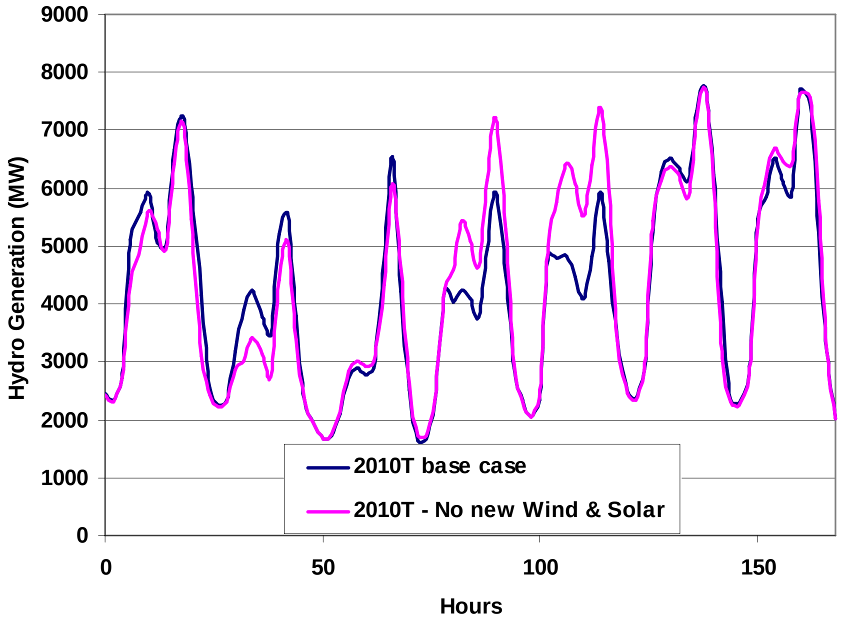


**Figure 76. One Week Change in California Hydro Operation (2010T).**

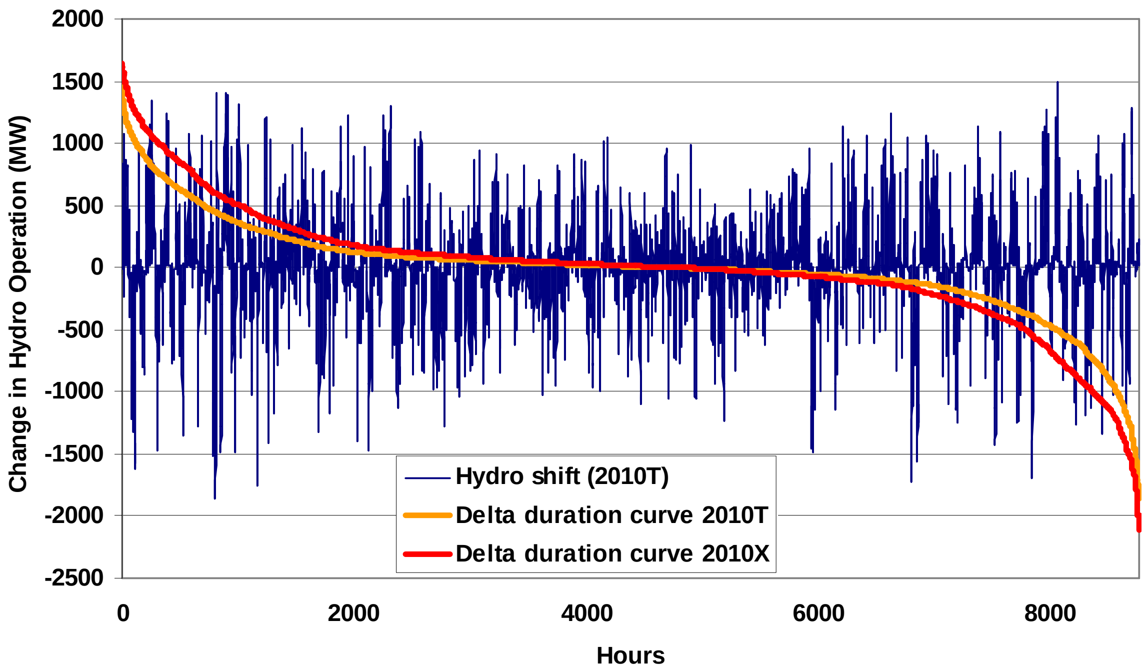


**Figure 77. Annual Change in California Hydro Operation (2010T and 2010X).**

There was some concern that the analysis might rely too heavily on hydro outside of California. With the exception of a few of the larger units (Chief Joseph, Hoover and Glen Canyon) the hydro outside of California was scheduled against the load curves for the local region, not the entire system. Hydro within California was scheduled against the local area loads (i.e. PG&E, SCE, SMUD, etc.). A later section examines the flows on the California – Oregon Interface and the overall impact on the Northwest hydro. Figure 78 shows the change in hydro generation for all of WECC. This curve has a similar shape to the hydro changes in California with the changes now falling mostly within +/- 2000 MW. Figure 79 is an annual histogram of the hourly changes both inside California and for all of WECC. The similarity of the curves demonstrates that most of the shift is happening within the California borders.

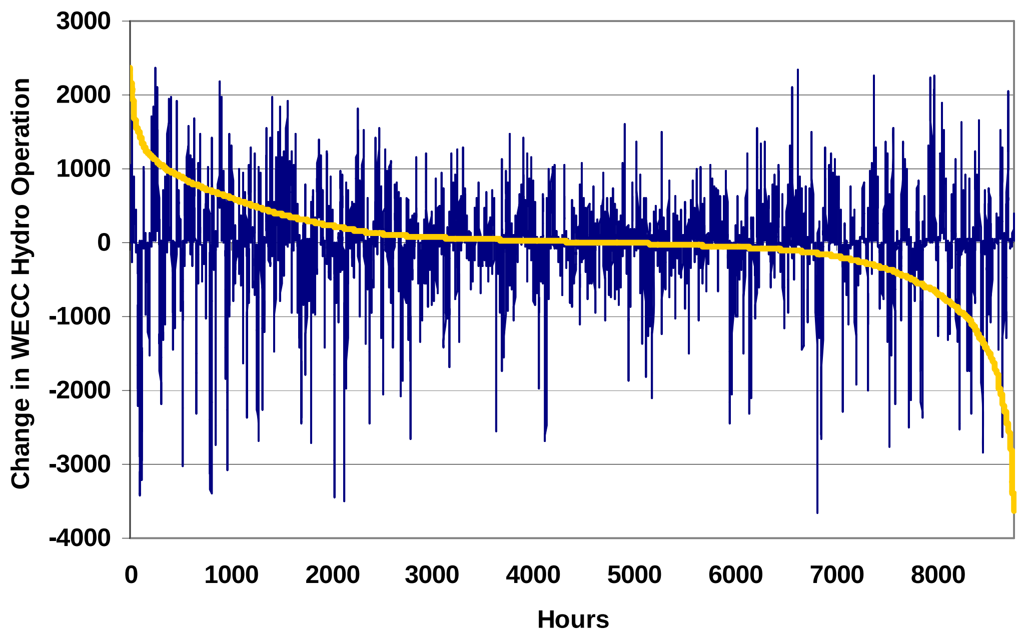


**Figure 78. Annual Change in WECC Hydro Operation (2010T).**

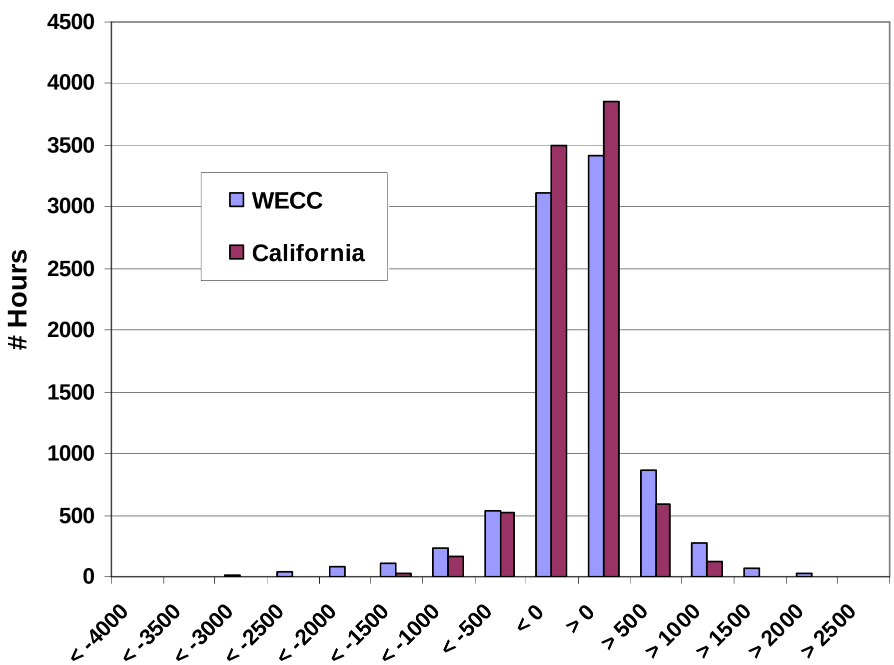


**Figure 79. Annual Histogram of Hydro Shift (2010T).**

Figure 80 shows the annual duration curve of the operation of the California pumped storage hydro, PSH. As expected, the PSH operation increased as the level of renewables increased. Although the maximum operating levels were reached for a few hundred hours per year it does not appear from these curves that additional PSH resources are required for the system. As will be shown later, the utilization of the PSH increases if the maneuverability of the conventional hydro is significantly constrained.

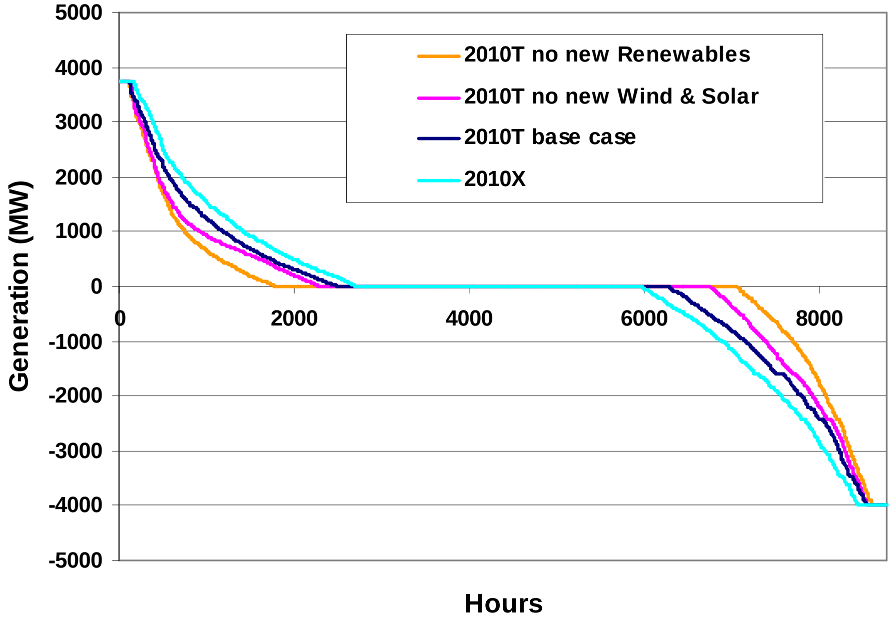


**Figure 80. Annual Duration Curves - California Pumped Storage Hydro Operation.**

So, what generation is being displaced? As discussed before and shown in Figure 81, the California combined cycle generation drops significantly as the renewable generation is added. The simulation assumed that combined cycle units could only ramp down to 50% of their capacity. Any further reduction would require them to be de-committed for a period of time. As will be shown, this is well within the design characteristics and historical operating capability of most existing and future combined cycle units.

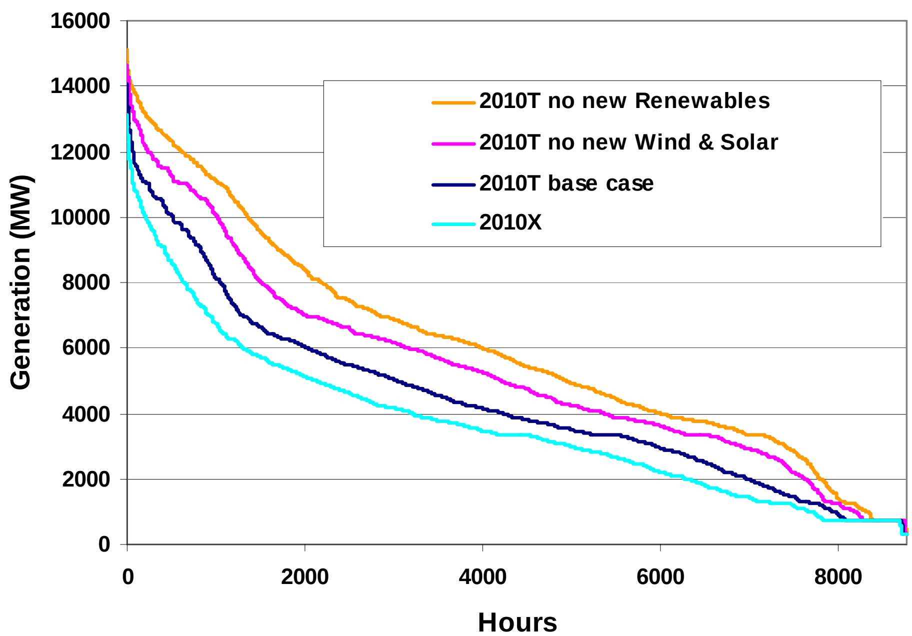


**Figure 81. Annual Duration Curves - California Combined Cycle Generation.**

The curves in Figure 82 show the final area of impact. As mentioned earlier, not surprisingly the imports into California decreased substantially when significant amounts of new generation were added to the California grid. Based on economics for the entire WECC the simulation only calculated imports into California. Historically California has also exported energy to the northwest during low load nighttime periods. These exports would help to reduce any difficulties that might be encountered in the low load periods and would improve the ability of the system to integrate additional renewable generation.

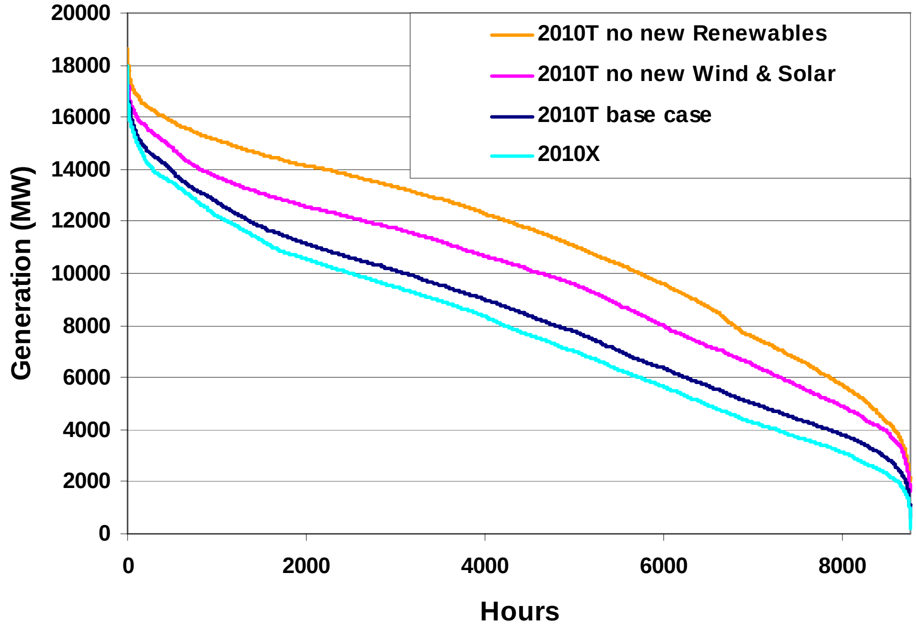


**Figure 82. Annual Duration Curves - California Imports.**

### *4.4.1. California Hydroelectric Operation*

Figure 77 showed that the system might need to shift the hydro roughly +/-1,500 MW to fully accommodate the variability from the additional 7,000 MW of wind and solar generation in the 2010T scenario. The question is "How much variability is there in the hydro?" Figure 83 shows the historical operation of the California hydro for sample weeks in May of 2004 and 2006. This data was provided by the  California ISO. The year 2004 was a "typical hydro" year and the curve in Figure 83 shows the hydro varying over 4,000 MW over the course of the week. The year 2006, however, was a "high hydro" year and the variations in the hydro were much less pronounced. But even in this "high hydro" week there was almost 2,000 MW of difference between the peak and valley operation of the hydro.

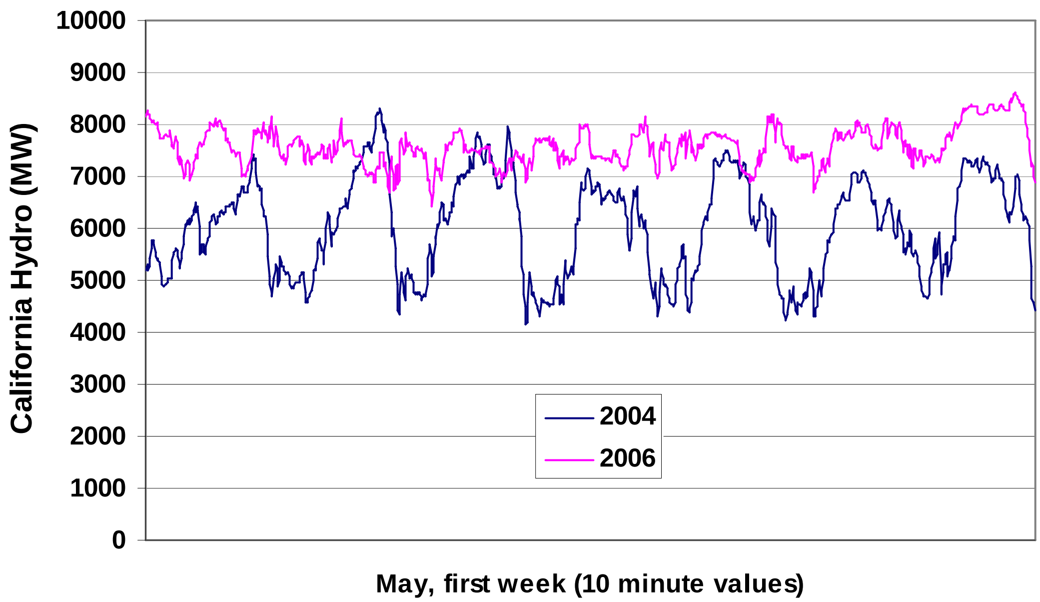


**Figure 83. California Historical Hydro Operation - Sample May Week.**

The curves in Figure 84 show the historical operation for the entire month. This shows that the hydro might be expected to vary its operation by as much as 2,500 MW even over the course of a very wet month. Figure 85 and Figure 86 show the chronological California ISO hydro operation for the months of June and July of 2004 and 2006. Figure 87 presents the data from the last three curves in a duration format. These show that even the high hydro months may be expected to have up to 4,000 MW of variation within the month and that typically the variation might be as much as 5,000 MW or even more. This would seem to indicate that certainly in typical years, but even in high hydro years there should be sufficient flexibility in the hydro to accommodate significant amounts of intermittent renewable additions.

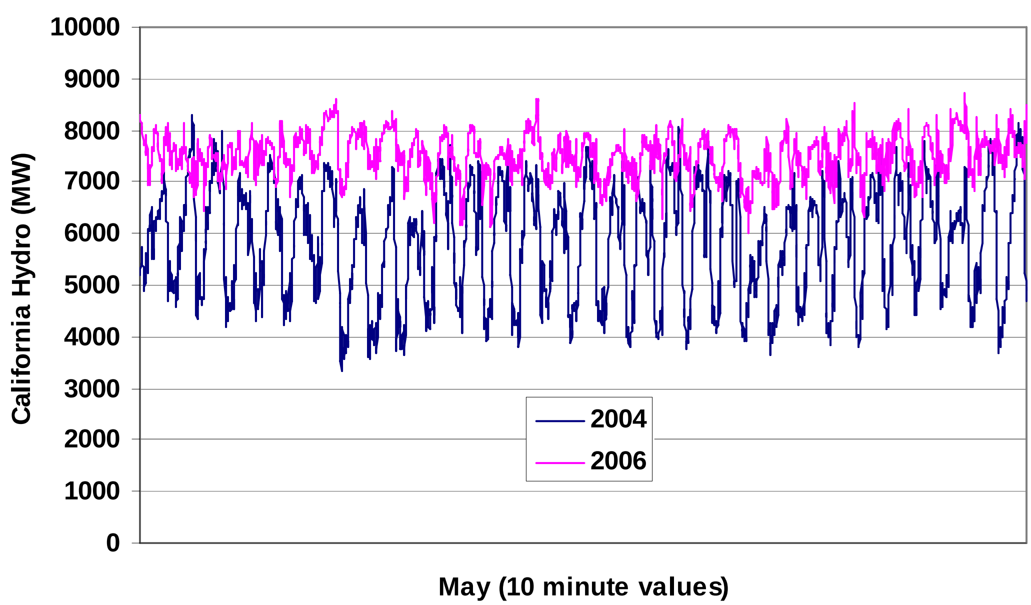


**Figure 84. California Historical Hydro Operation – May.**

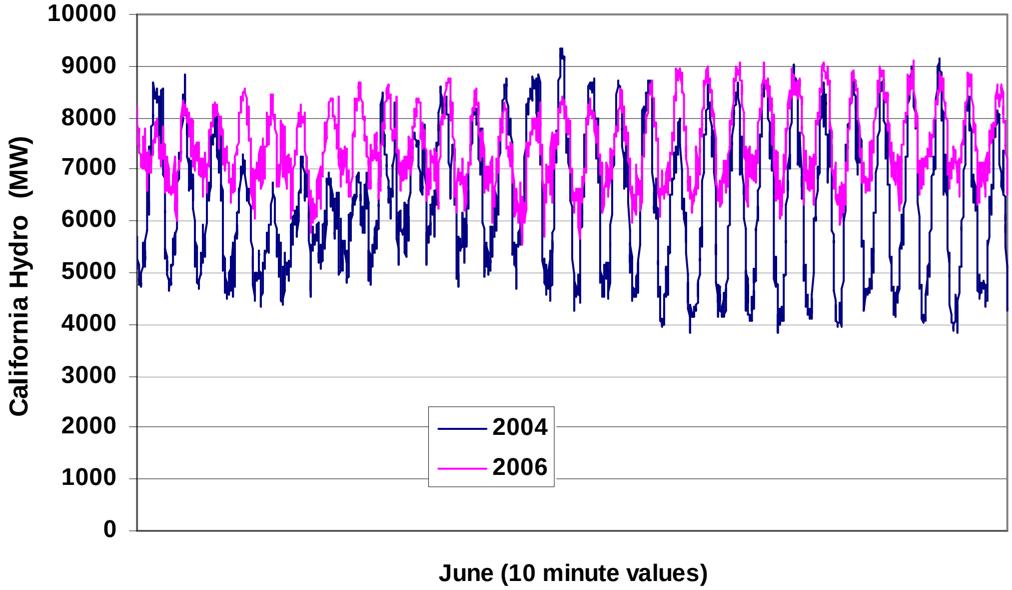


Figure 85. California Historical Hydro Operation – June.

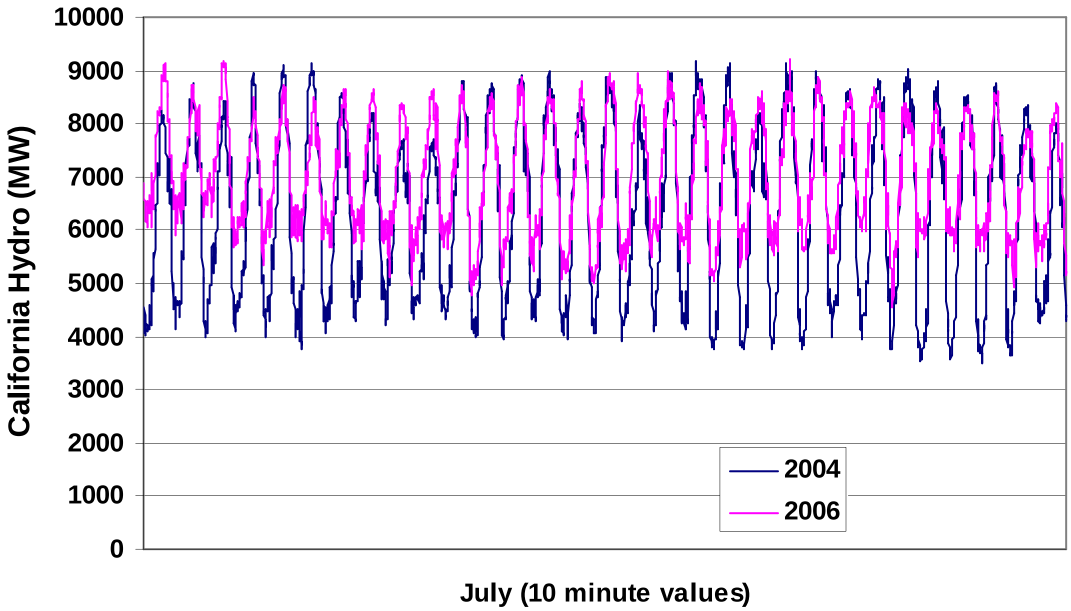


Figure 86. California Historical Hydro Operation – July.

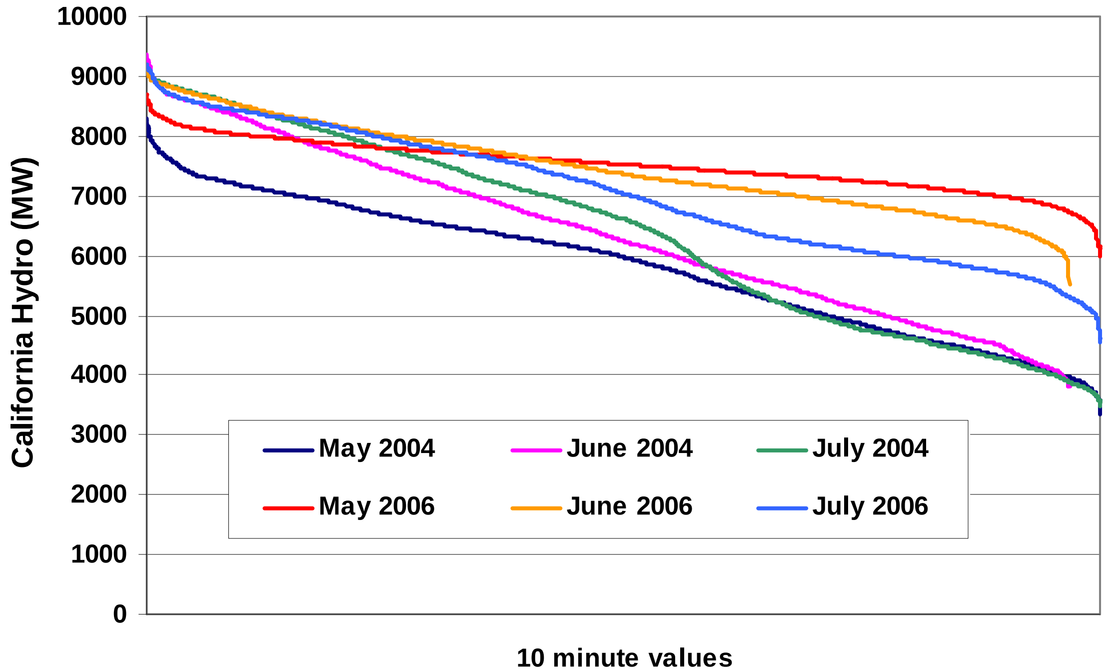


**Figure 87. California Hydro Historical Monthly Duration Curves.**

It has been pointed out that the hydro has many constraints placed upon it and is not under the direct control of the California ISO. While this is true, it is also true that the hydro will vary its operations, within the limits placed on it, in order to chase the higher marginal cost values in the higher loads. It would seem that if the California ISO were to publish the forecasted wind and solar operation along with the forecasted loads that the hydro operators would strive to operate to the net "load minus intermittent" schedules as they currently operate to the forecasted loads. The variability of the hydro is examined in more detail in Section 4.4.4

### *4.4.2. Combined Cycle Operation*

Based on our understanding of the physical limitations of the units and discussions with other operators the combined cycle units were modeled with a minimum operating point equal to 50% of their rated capacity. If generation had to be reduced below the 50% level then the unit would be de-committed for a minimum of 8 hours. The model factored in the minimum down time for each of the units as well as their start-up costs to decide if the units should be left on at their minimum operating point or turned off. In order to validate our assumptions we examined the hourly output from various large combined cycle units operating in California. This output was determined from the Continuous Emissions Monitoring System, CEMS, database for 2005. The results for three of these units are shown in Figure 88, Figure 89 and Figure 90. The first unit cycles from above 800 MW to roughly 400 MW on a daily basis and occasionally cycles down to about 260 MW or roughly 30%. The second unit cycles down to 60% routinely although there are multiple instances where it cycles to about 30%. The third unit operates in a similar manner. Although this was not an exhaustive search, it indicates that 50% is a reasonable assumption and might even be conservative.

Newer combined cycle units can cycle to 30% output and still maintain emission levels. In addition, many existing units could be retrofitted to improve their cycling capability. Higher penetrations of intermittent generation require a system that can respond to their fluctuations. It would be beneficial for the market to encourage increased cycling capability in the generation mix.

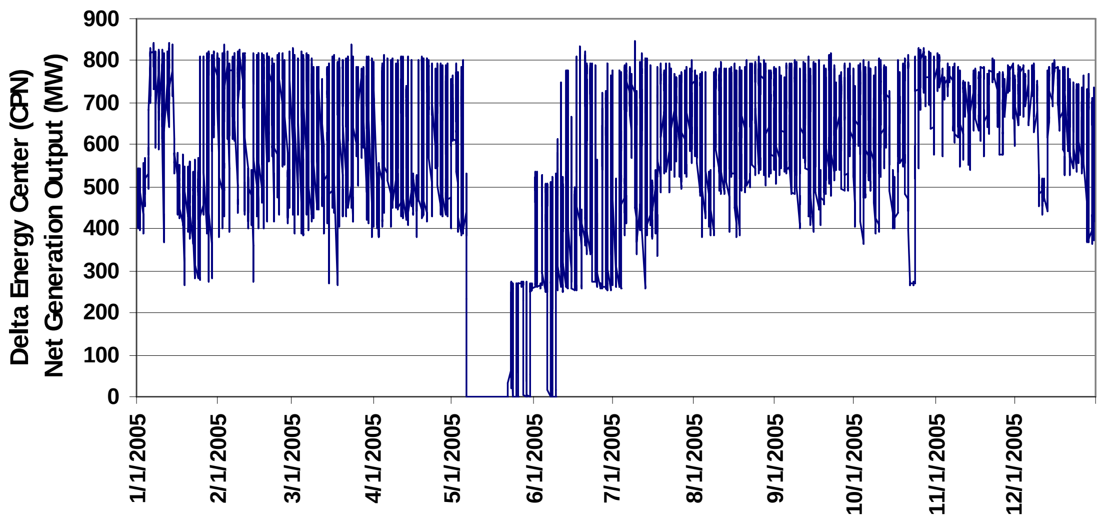


**Figure 88. 2005 CEMS Data – Delta Energy Center.**

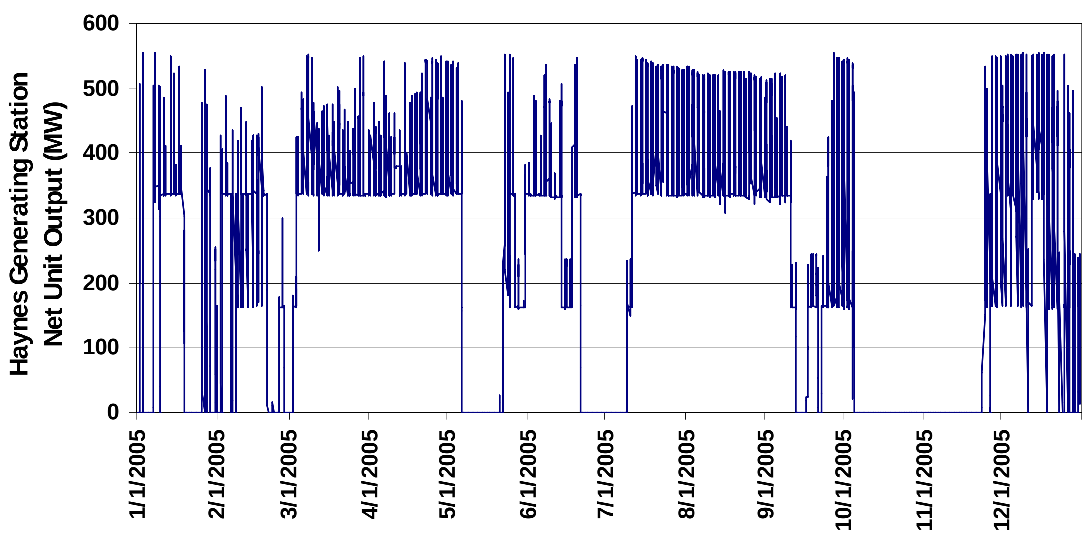


**Figure 89. 2005 CEMS Data – Haynes Generating Station.**

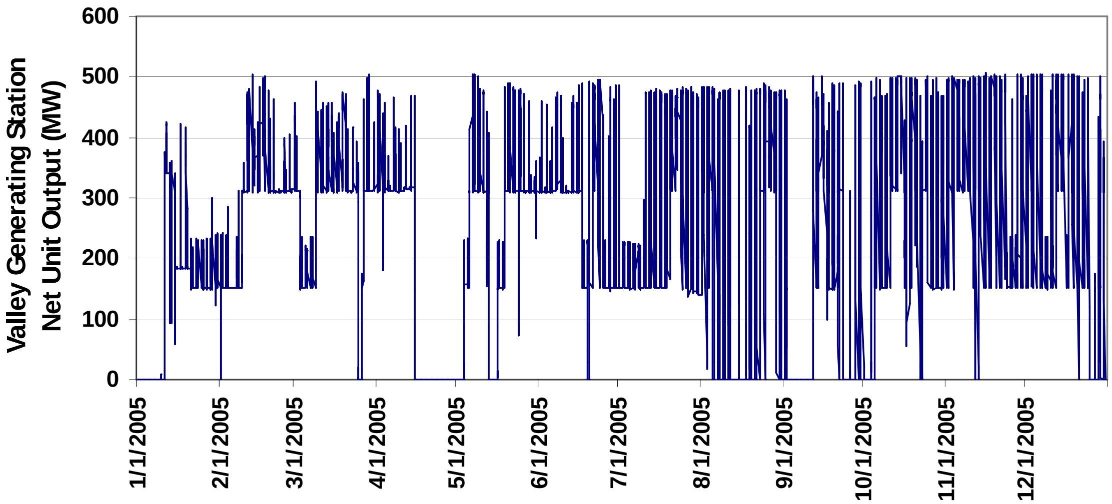


**Figure 90. 2005 CEMS Data – Valley Generating Station.**

### *4.4.3. Ramp Rate and Range of Operation*

One of the key operational factors that is of interest is how much ramping capability is available each hour based on the commitment and dispatch of the generation and the corresponding unit ramping capabilities. Figure 91 shows a sample unit commitment schedule by generation type for a week. Figure 92 shows the corresponding unit dispatch. Based on the ramp rates of the individual units the amount of ramp up and down capability, in MW/minute, was then calculated as well as the available range up and down, in MW. As an example, a unit's contribution to the system range up capability equals it capacity minus its dispatch for the hour. The unit's ramp up capability is equal to its capacity times its ramp rate as long as this is less than the calculated range. The resulting totals are shown for the sample week in Figure 93. Since the ramp down capacity can be critical, particularly during low load periods, this is shown in Figure 94 with a breakdown by unit type. Although the hydro generation is obviously providing the majority of the ramping capability, Figure 95 shows that even without the hydro the system would generally have at least 200 MW/minute available. Based on the statistical analysis presented in the previous section, three standard deviations of the one minute delta is expected to be about 150 MW.

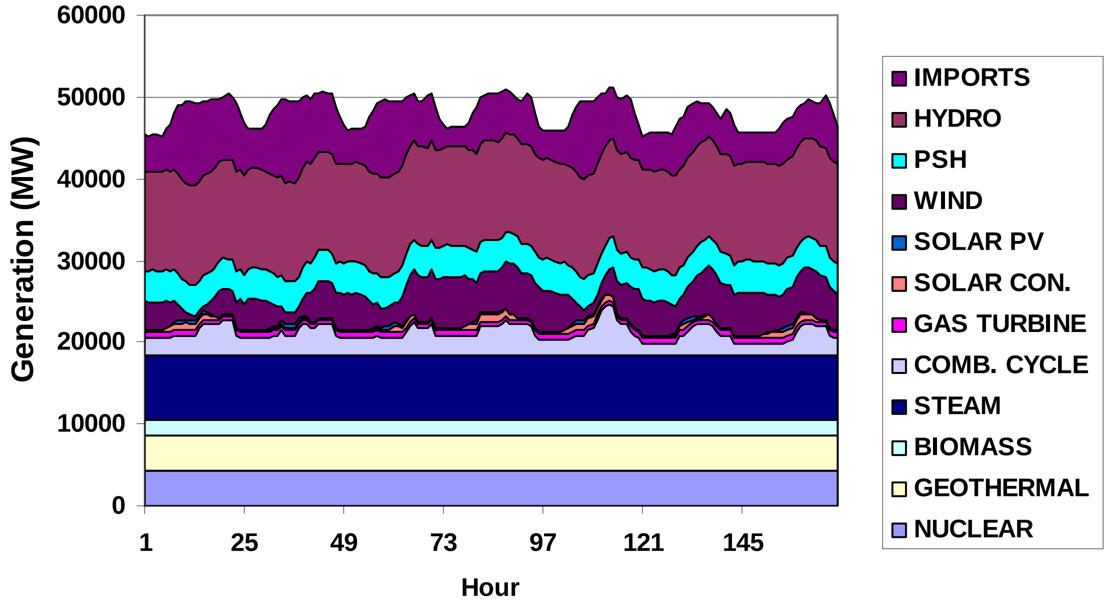


**Figure 91. Commitment – Week of May 10th.**

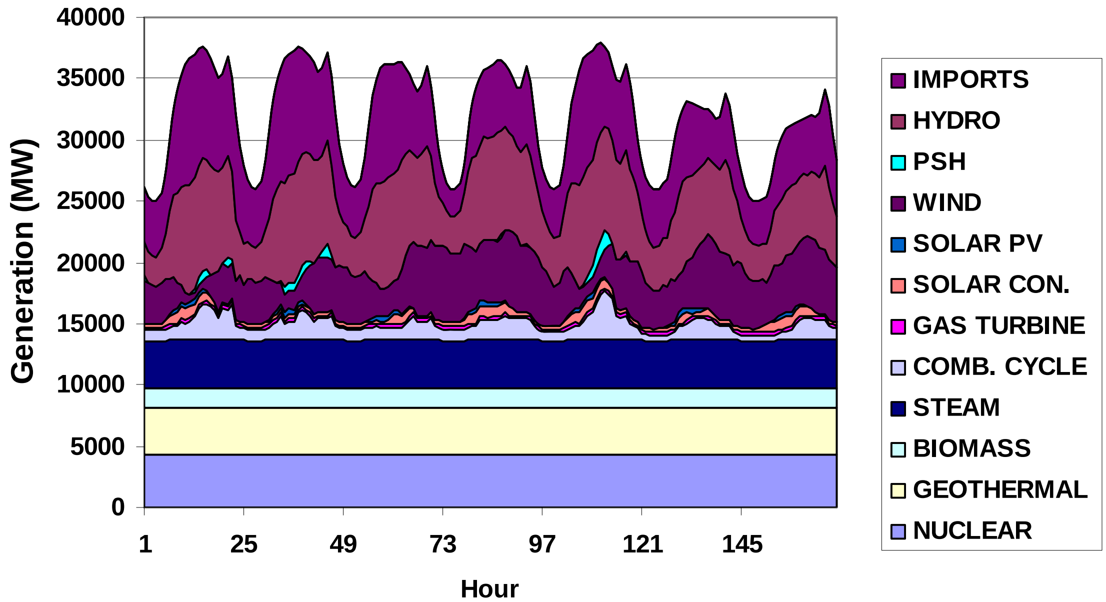


**Figure 92. Dispatch – Week of May 10th.**

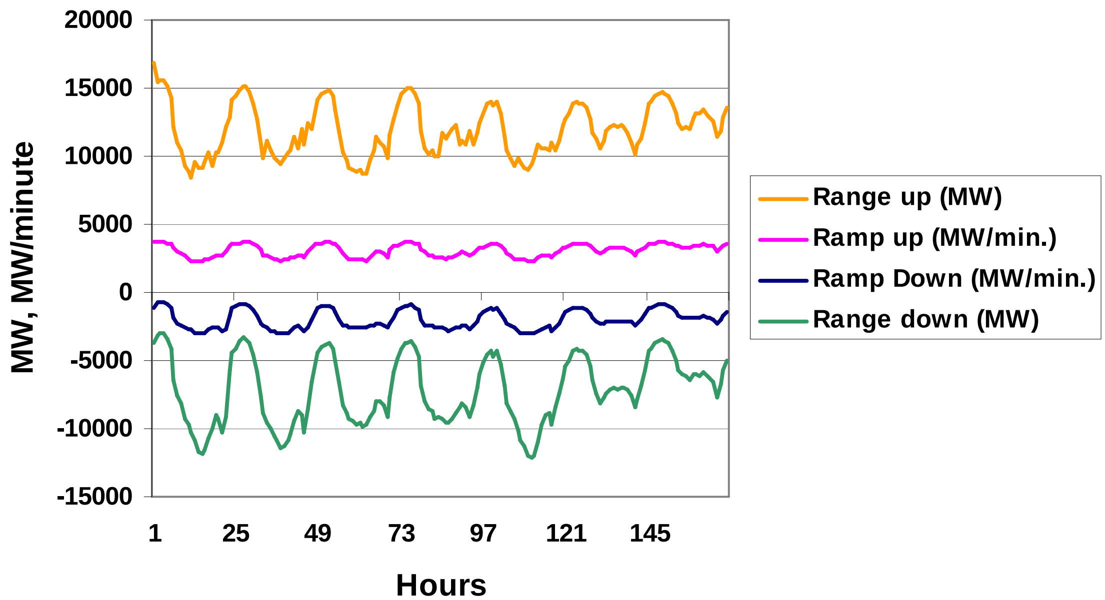


**Figure 93. Ramp Rate and Range Capability - Week of May 10th.**

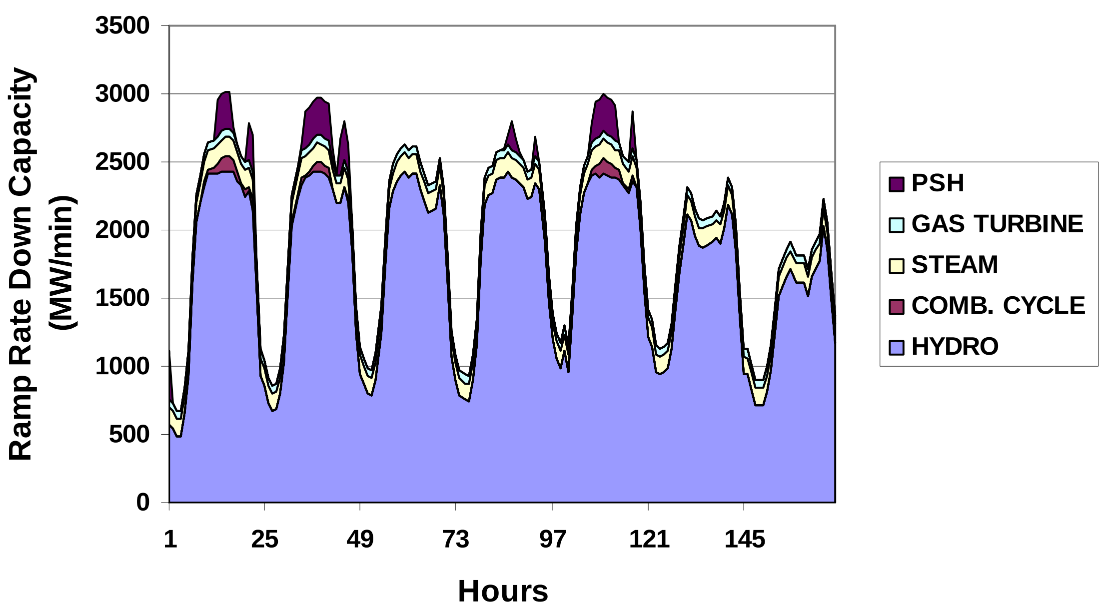


**Figure 94. Ramp Rate Down Capability - Week of May 10th.**

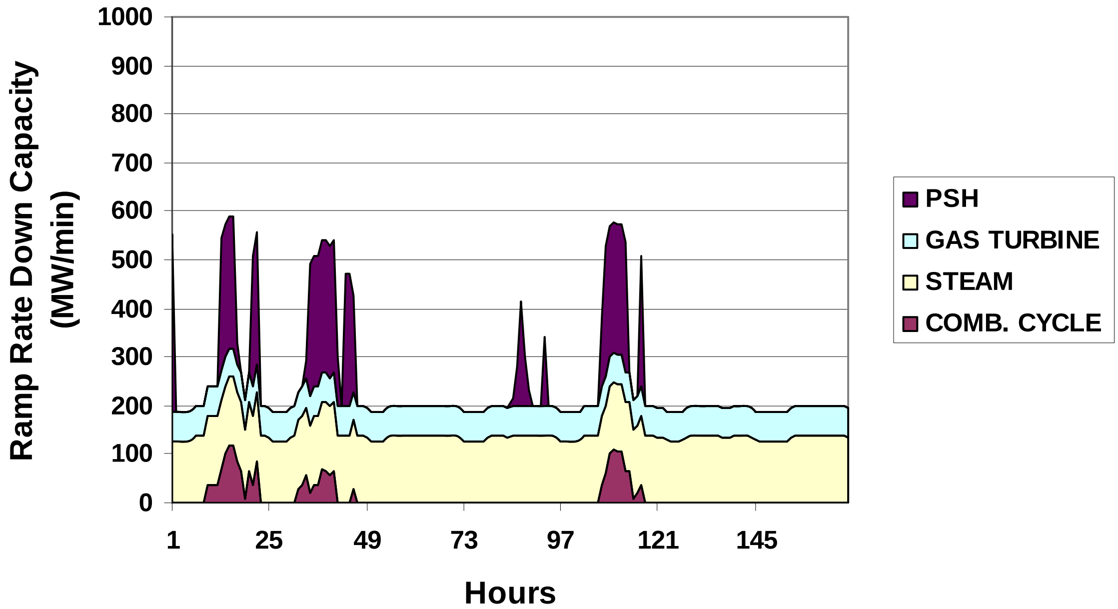


**Figure 95. Ramp Rate Down Capacity Without Conventional Hydro – Week of May 10th.**

The scatter plots in Figure 96 and Figure 97 were created to show the ramp rate and range down capability versus the California load. As expected, these values typically exceed what is generally needed in all but a handful of the low load hours. As the loads increase the ramp rate and range down are no longer critical. The May 15th values that are flagged are one of the time frames examined in the quasi-steady state analysis in Section 5.0

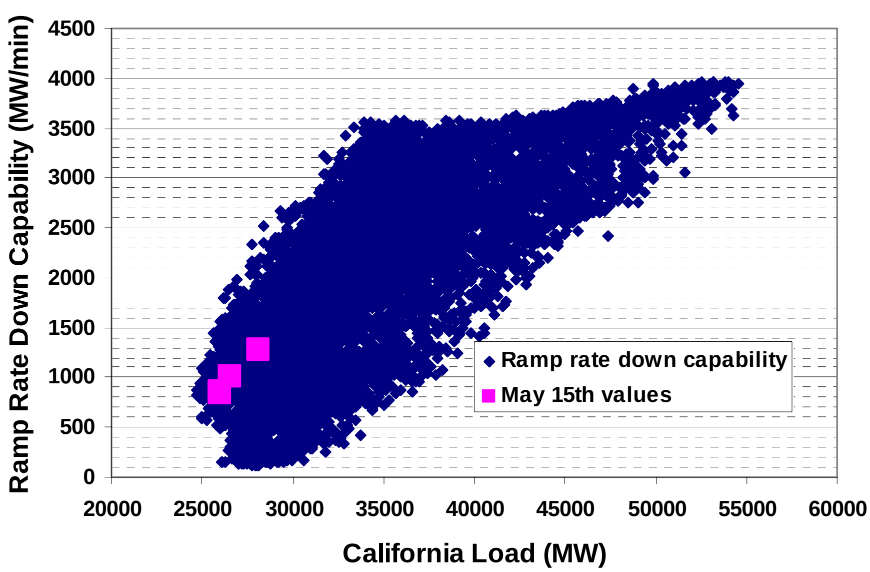


**Figure 96. Ramp Rate Down Capability Versus California Load (2010X).**

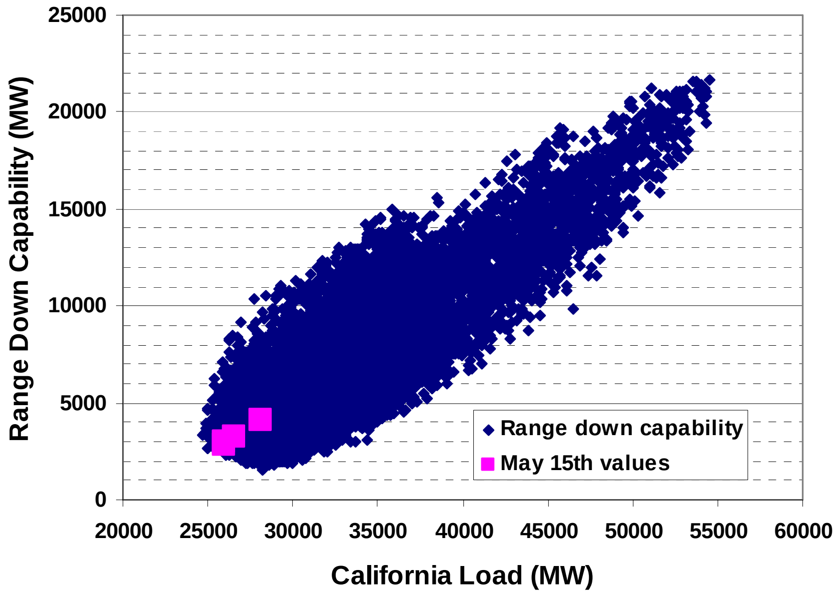


**Figure 97. Range Down Capability Versus California Load (2010X).**

In a similar manner, Figure 98 and Figure 99 show the ramp rate and range up capability. These curves would indicate that there is always sufficient ramp rate and range up capability on the system.

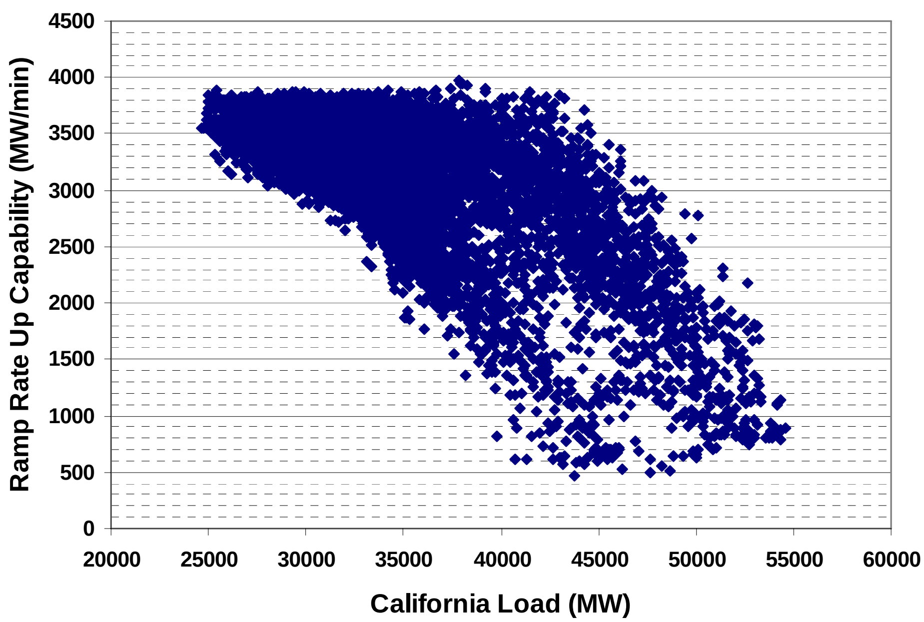


**Figure 98. Ramp Rate Up Capability Versus California Load (2010X).**

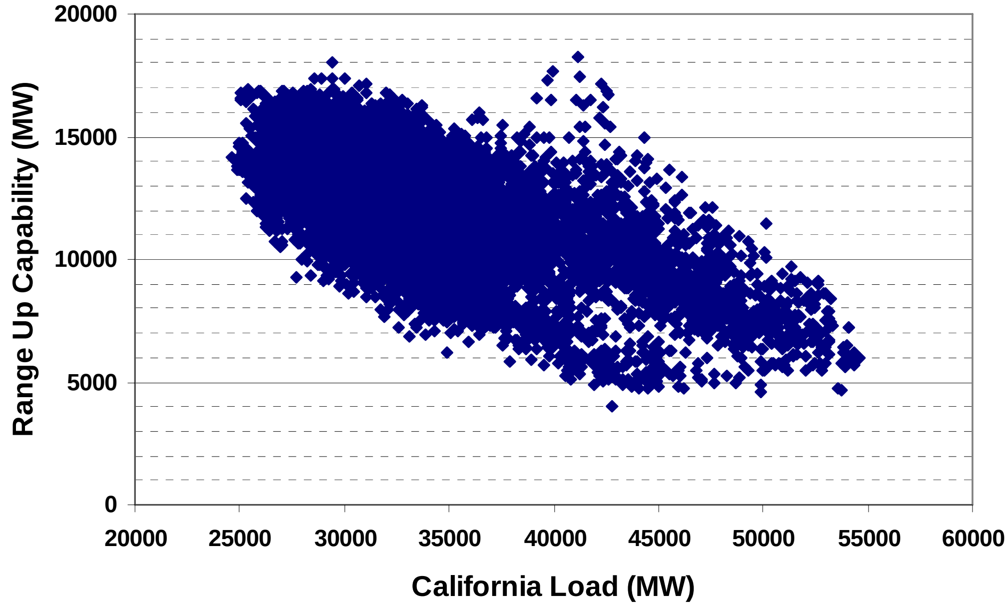


**Figure 99. Range Up Capability Versus California Load (2010X).**

The curves in Figure 100 show the annual ramp down capacity in duration curves for the various scenarios examined. Although there is some variation it doesn't seem to change significantly for the different scenarios.

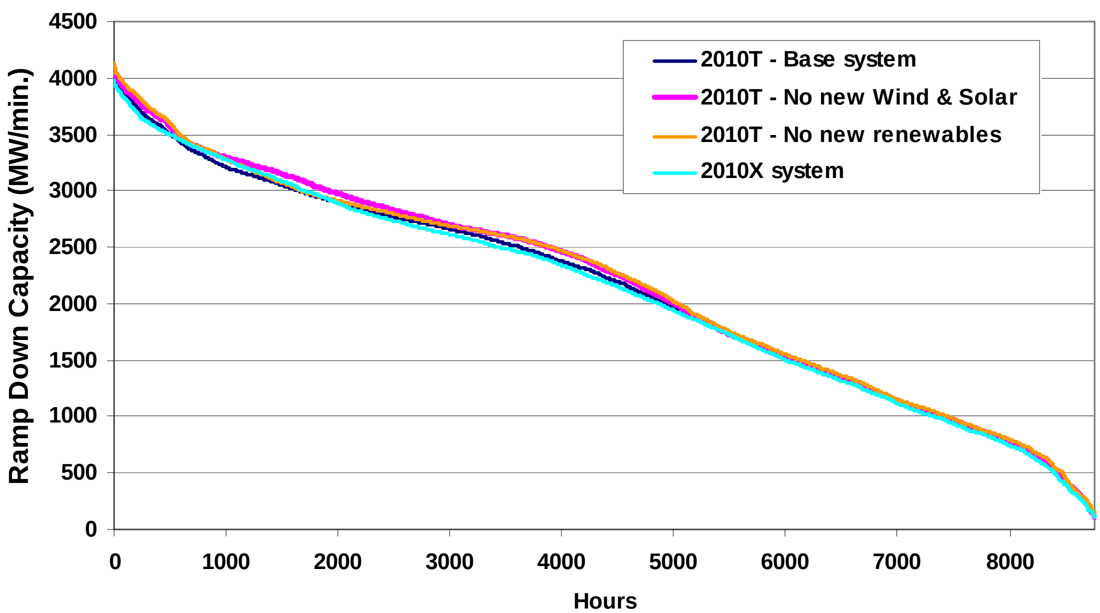


**Figure 100. Annual Ramp Rate Down Capability.**

The curves are expanded in Figure 101 to highlight the hours with lower ramping capacity. Again, it appears that only a handful of hours may fall within the 150 MW value needed to cover three standard deviations.

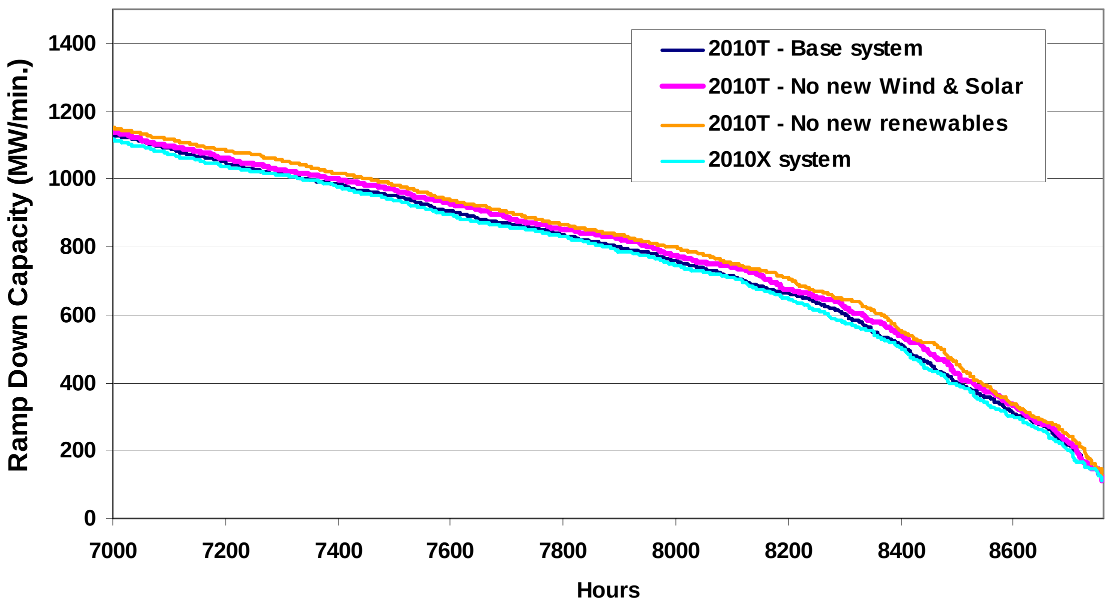


**Figure 101. Annual Ramp Rate Down Capability (zoom).**

### *4.4.4. Sensitivities*

It was indicated that the Helms pumped storage hydro (PSH) plant is often constrained in the pumping mode such that only two of the three pumps are capable of operating. A sensitivity case was run with the pumping capability reduced for the entire year. Figure 102 shows that under these conditions the operation changes slightly, but is limiting in the pumping mode for only a few additional hours. The variable costs of operation in California increased about $ 2 million per year with the reduced PSH capability.

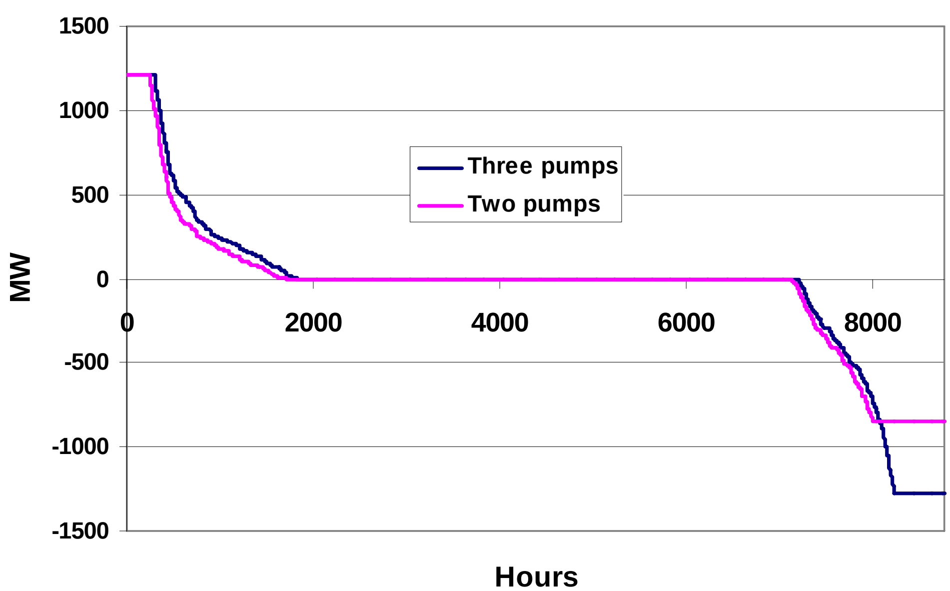


**Figure 102. Operation of Helms Pumped Storage Hydro (2010X).**

Figure 103 shows the daily minimum, maximum and range for the conventional hydro for all of 2006. Figure 104 shows the average daily hydro generation and range for the March through

August period for both 2004 and 2006. Since hydro was an important contributor to the overall system ramping capability two sensitivity cases were run with the hydro severely constrained. The hydro output was constrained to be between 50% and 75% of the unit rating, energy limits permitting. Figure 105 shows the impact on the hydro operation for a sample week in May for the 2010T scenario. The first sensitivity constrained the hydro for January through May, inclusive, and the second sensitivity constrained the hydro for the entire year. Figure 106 shows the impact on the California hydro over the course of the entire year for the base case and sensitivities. When the hydro was constrained for the entire year the total range of operation decreased from over 10,000 MW to roughly 4,000 MW. When constrained for the first five months the overall annual range didn't change, but the impact was still significant. The full year of constraints increased the annual operating cost in California by almost $70 million.  The California operating cost increased by less than $30 million per year when the hydro was only constrained for the first five months.

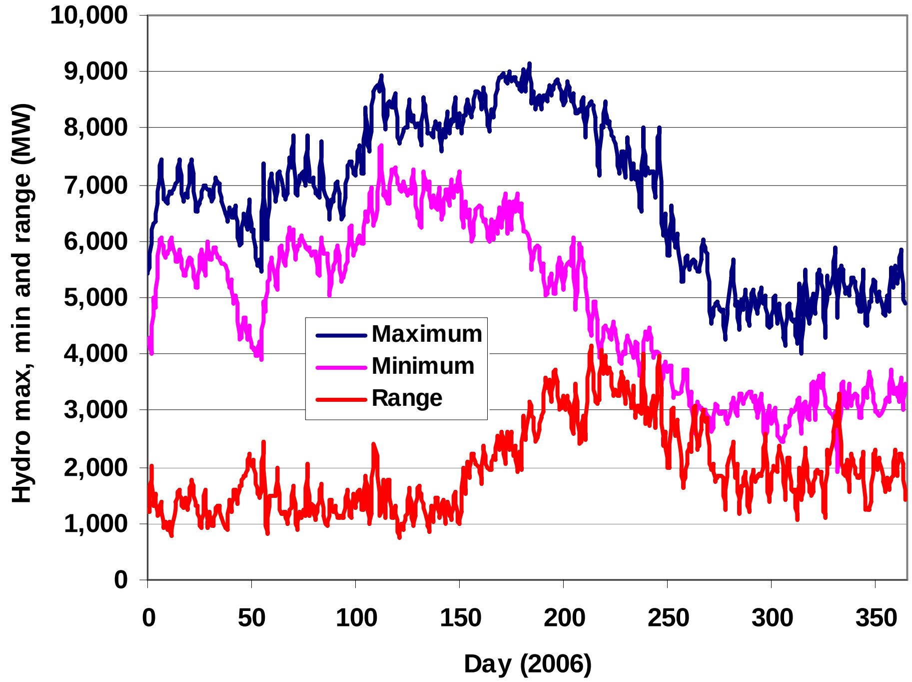


**Figure 103. Historical Hydro Daily Minimum, Maximum, and Range, 2006.**

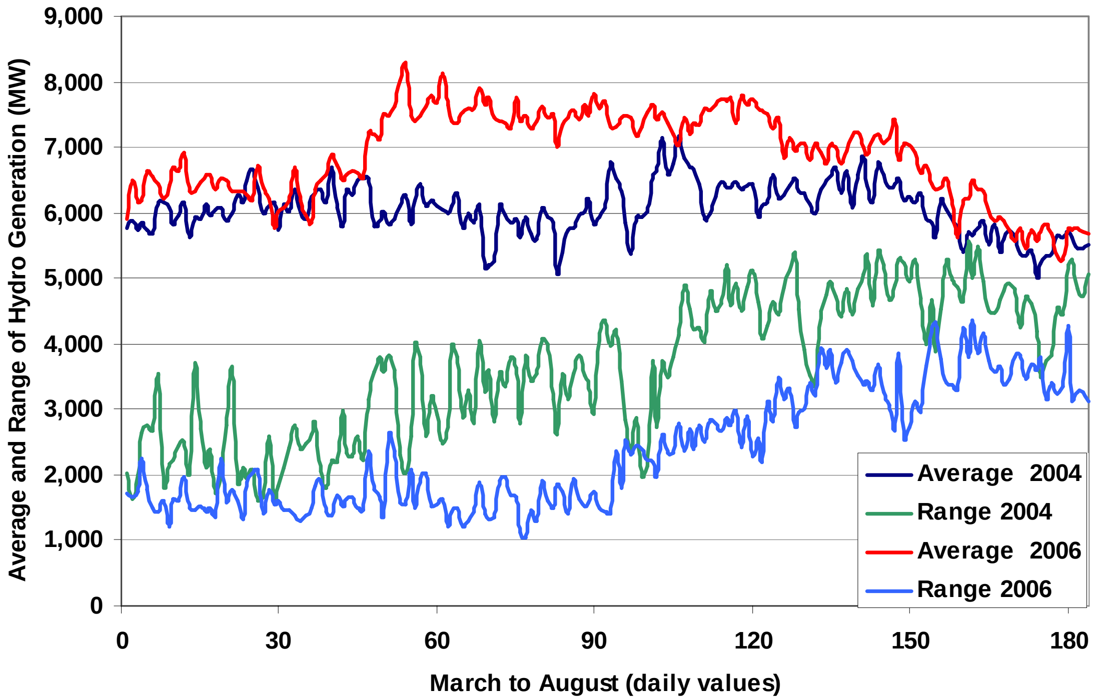


**Figure 104. Daily Range Of Hydro Operation, Summer 2004 and 2006.**

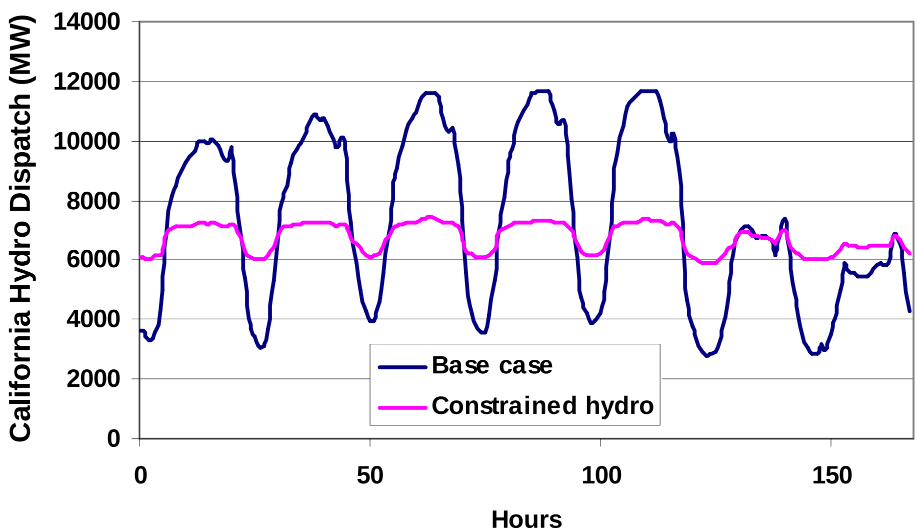


**Figure 105. Constrained Versus Base Hydro for a Sample May Week (2010T).**

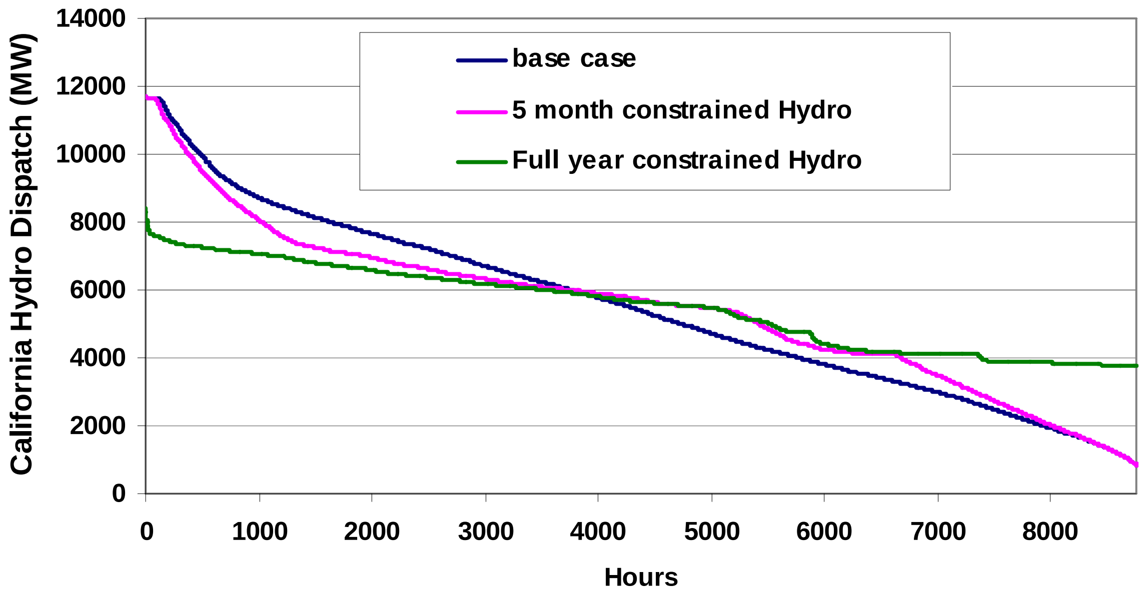


**Figure 106. Annual Duration Curve – California Hydro Generation (2010T).**

Figure 107 and Figure 108 show the new impacts on the California ramp down capability. The extreme case seemed to have sufficient ramping capacity for almost all of the hours, although the ramp down capability did drop below 200 MW/min for about 500 hours in the year. Although the five month constrained assumptions are still quite conservative the results show much less impact, particularly for the low load hours.

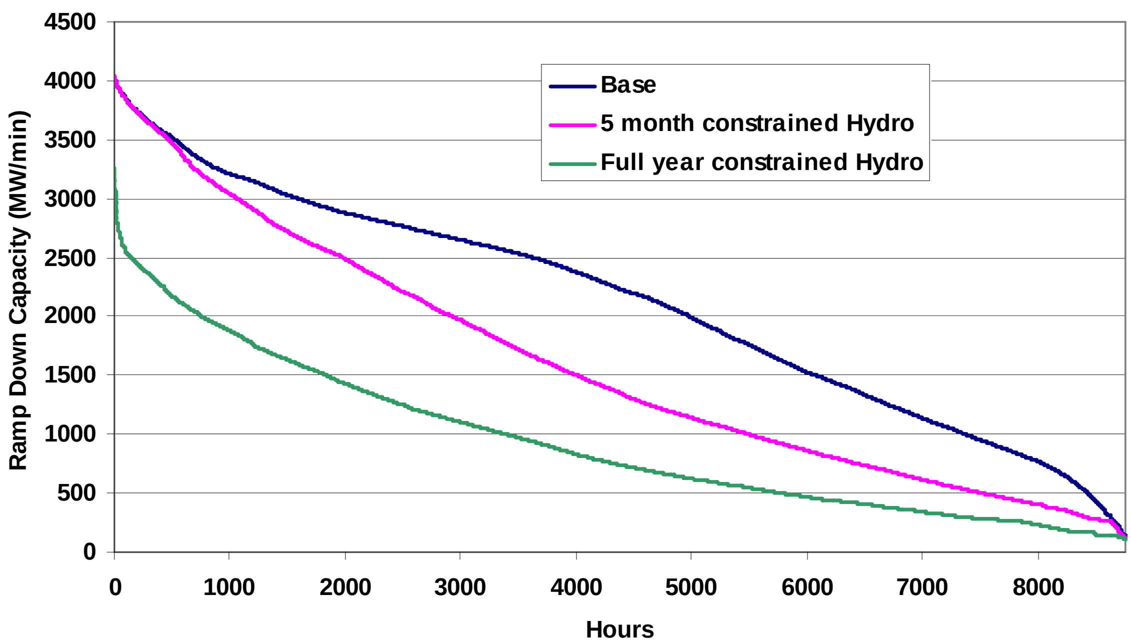


**Figure 107. Ramp Down Capacity With Constrained Hydro, 2010T.**

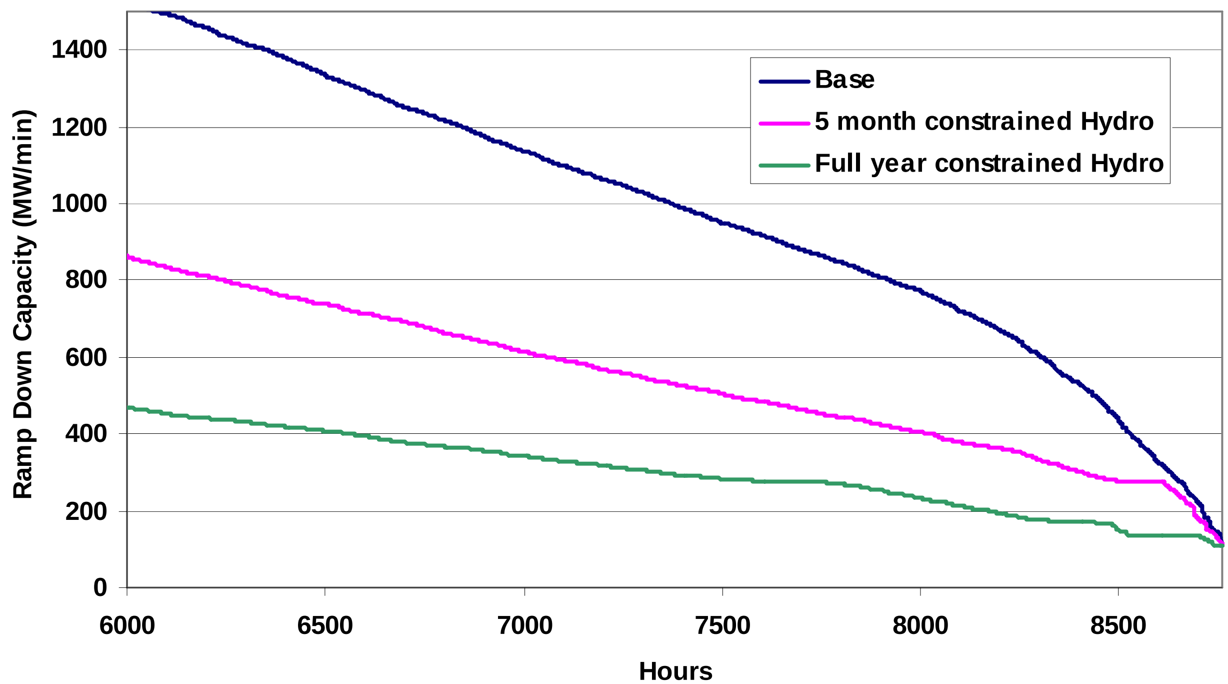


**Figure 108. Ramp Down Capacity With Constrained Hydro, 2010T (zoom).**

When the flexibility was removed from the conventional hydro then the system depended more on the Pumped Storage Hydro generation. Figure 109 shows the change in operation of the California PSH. The number of hours when the existing PSH is capacity constrained more than tripled when the hydro was constrained all year. The PSH also increased somewhat when the hydro was constrained for the first five months. The curves in Figure 110 show the historical change in operation for the Helms PSH plant over the six month period from March through August. As was simulated in Figure 109, the total PSH operation increases as the variability on the conventional hydro is reduced.

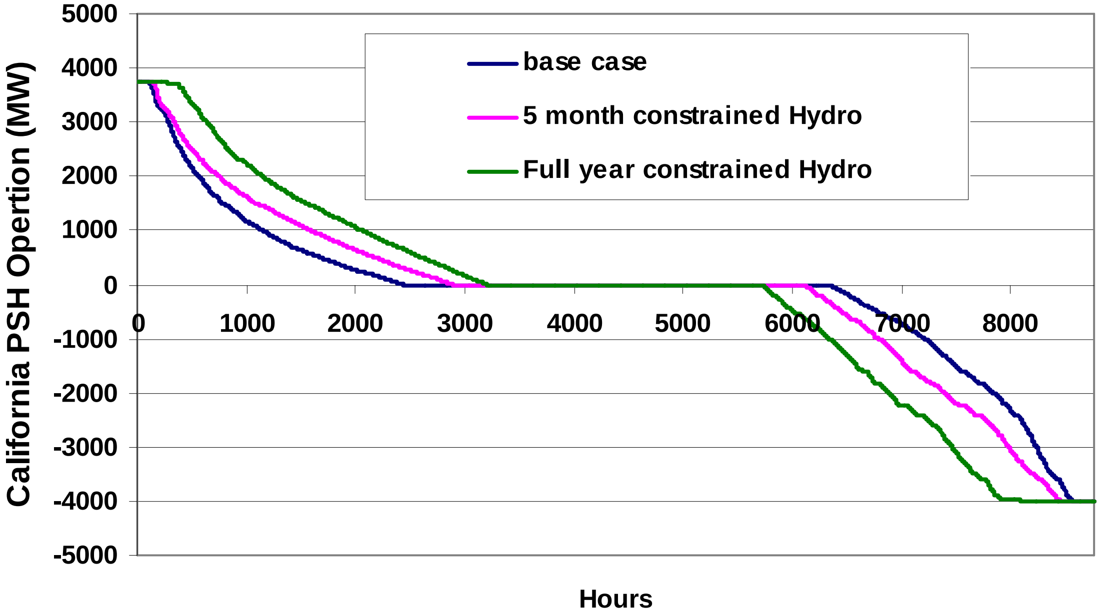


**Figure 109. Annual Duration Curve – California PSH Operation with Constrained Hydro (2010T).**

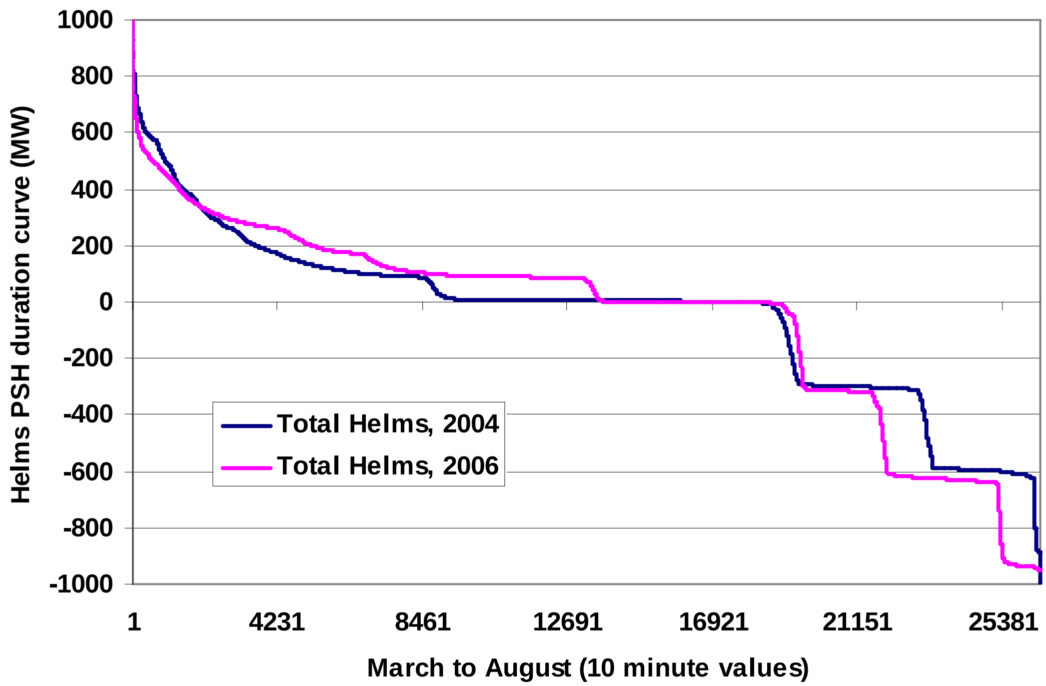


**Figure 110. Comparison of Helms Operation, Summer 2004 and 2006.**

The pumps (both PSH and conventional pumping loads) are also a potentially important source of system maneuverability. Figure 111 shows a typical week of pumping operation both with and without the pumped storage facility at Helms. Figure 112 shows the daily range of operation for all of 2006. California currently has over two thousand MW of pumps that cycle during the day to take advantage of the low off-peak cost of energy. If increased levels of wind generation cause the low cost periods to shift then the pumps will likely follow. In fact, it may be economically attractive to add additional pumps to increase the maneuverable range available.

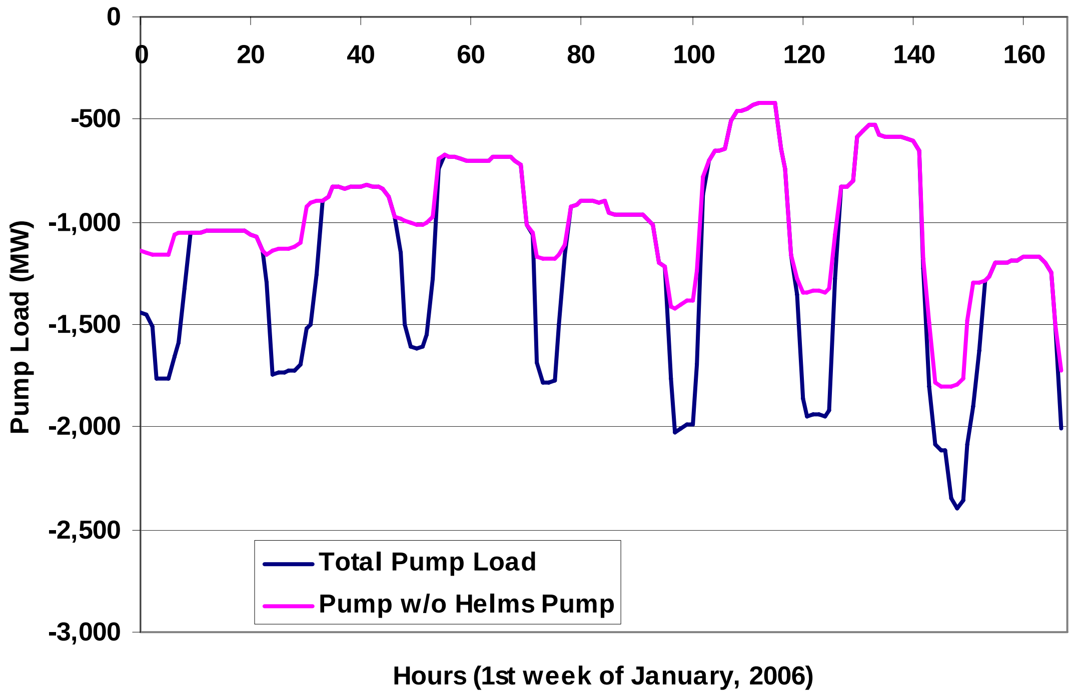


**Figure 111. Sample Week of Pumping Operation, January 2006.**

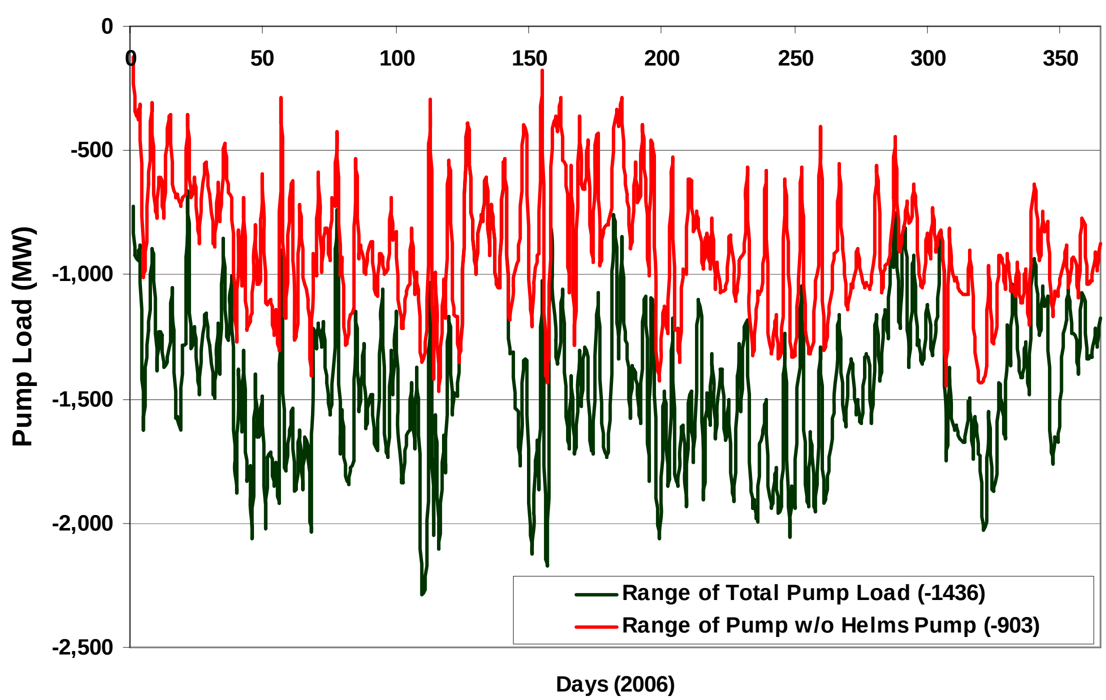


**Figure 112. Historical Pumping Operation, 2006.**

## 4.5. Emissions

One of the major benefits of renewable generation is the reduction of emissions caused by fossil fuel fired generation. Figure 113 shows that the NOX emissions in California would decrease by almost 500 tons per year and that SOX emissions would decrease by over 250 tons per year for the 2010T scenario with all new renewable generation added. But since much of the generation shift happens outside of California it is important to look at the WECC impact. Figure 114 shows that within WECC the NOX emissions would decrease by 2500 tons and the SOX emissions would decrease by 500 tons. Figure 115 and Figure 116 show the corresponding reductions for the new wind and solar generation only.

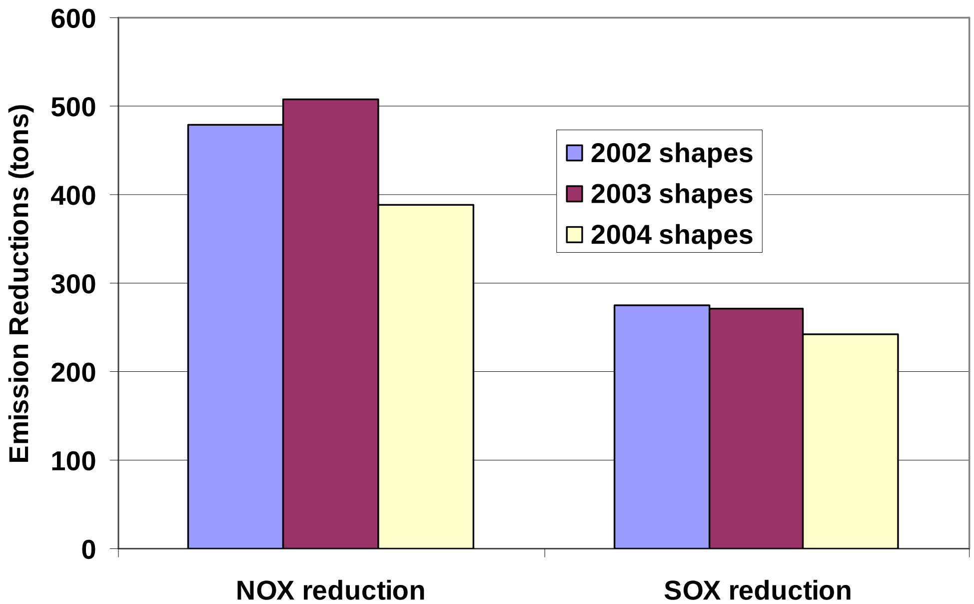


**Figure 113. California Emission Reductions Due to Renewables (2010T).**

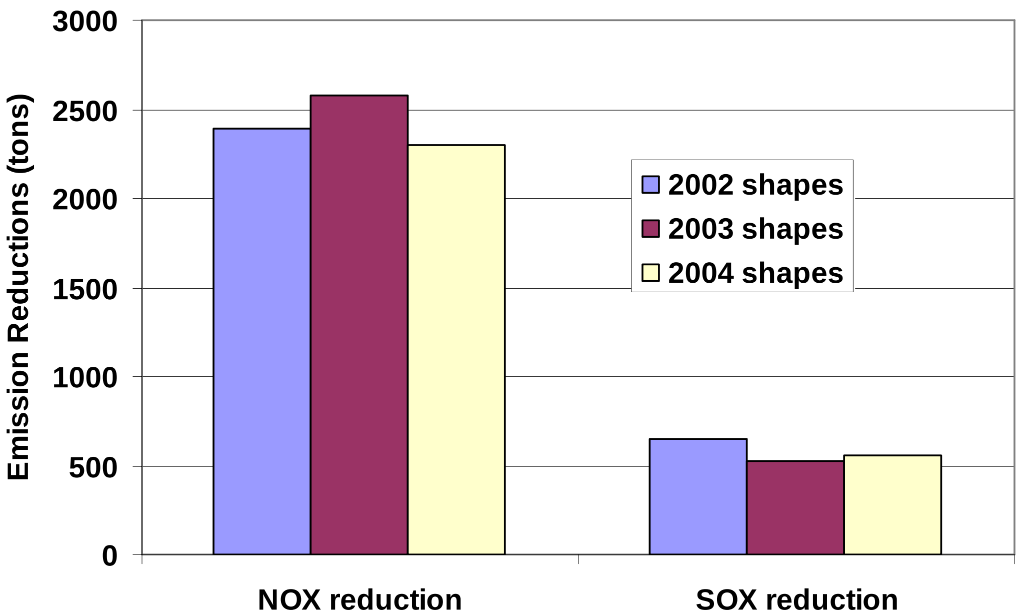


**Figure 114. WECC Emission Reductions Due to renewables (2010T).**

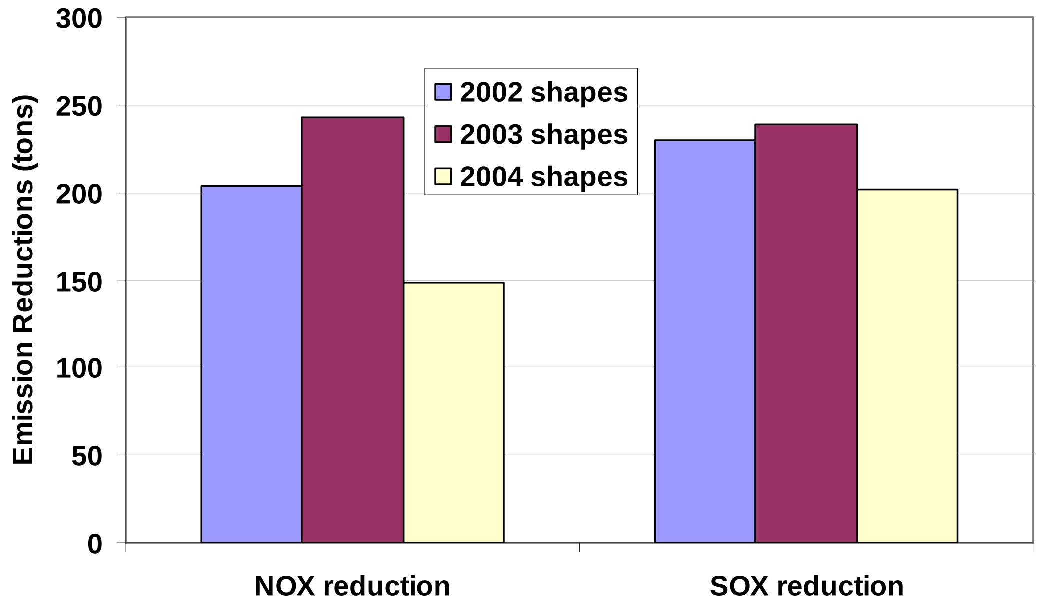


**Figure 115. California Emission Reductions Due to New Wind and Solar Generation (2010T).**

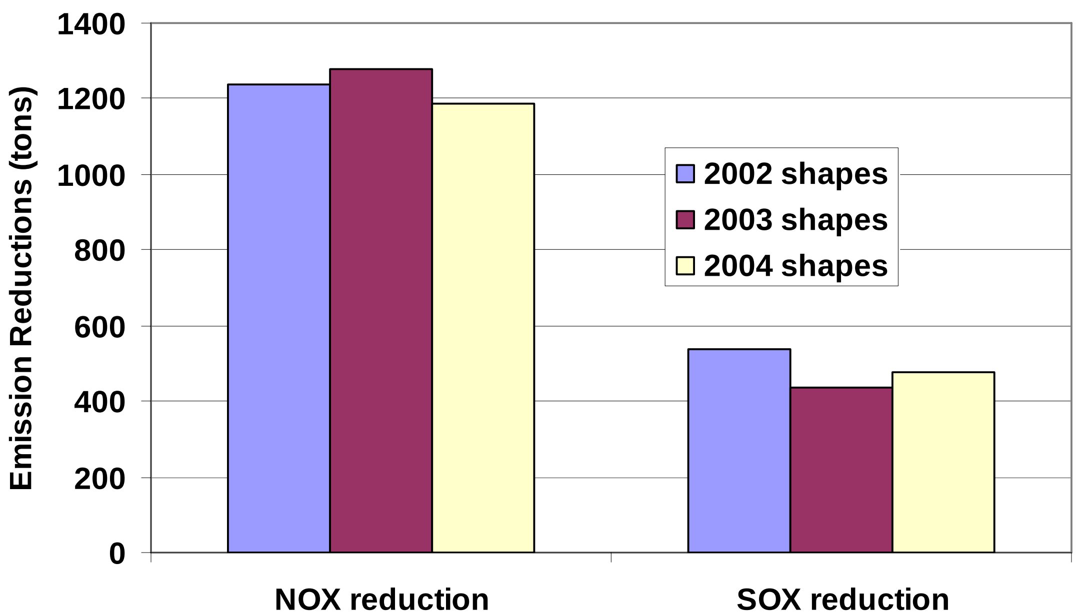


**Figure 116. WECC Emission Reductions Due to New Wind and Solar Generation (2010T).**

## 4.6. Transmission Path Loading

The final operational impact that was examined was the impact on the transmission loading. Although some new transmission will be required to connect the new generation into the grid, the focus was on the major interfaces into and within the state of California. Figure 117 shows the flows on Path 15 increasing in the South to North direction, but decreasing in the opposite direction. Figure 118 shows the flows consistently reducing from Arizona to California as more resources are added onto the California grid. In particular, the hours with congestion are significantly reduced. Similar impacts are shown in Figure 119 and Figure 120 for the West of Colorado River and Southern California Import interfaces. So while some new transmission is required, congestion on many of the existing transmission corridors are relieved.

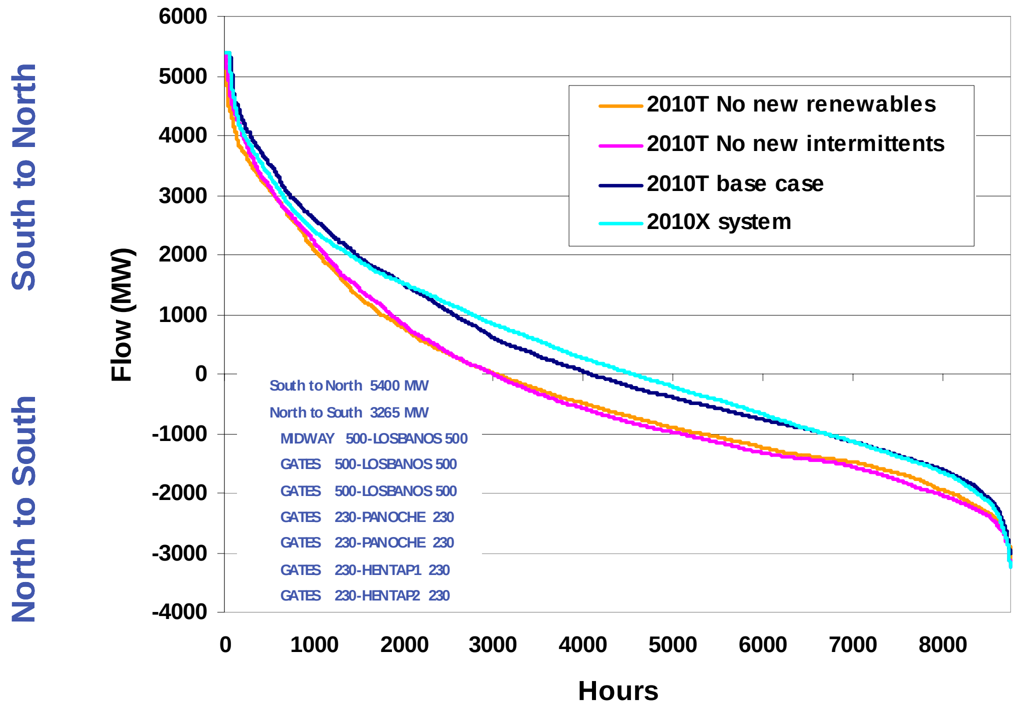


**Figure 117. Transmission Flow Duration Curves – Path 15: South of Los Banos.**

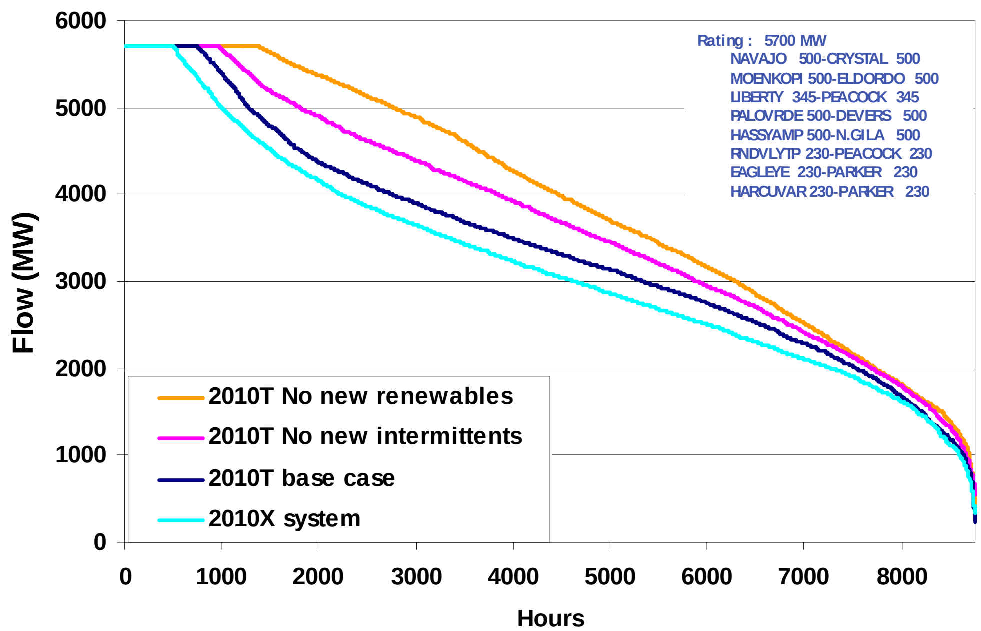


**Figure 118. Transmission Flow Duration Curves – Path 21: Arizona to California**

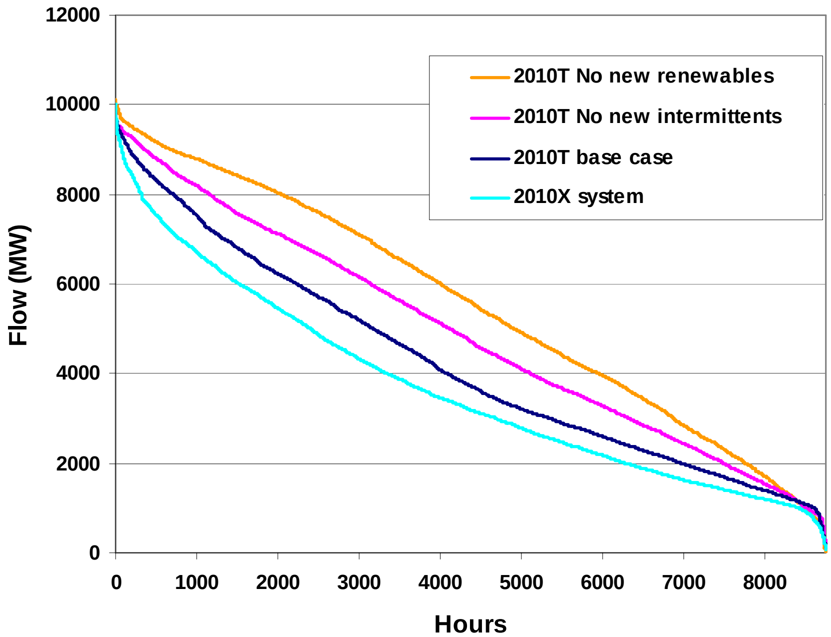


**Figure 119. Transmission Flow Duration Curve – Path 46: West of Colorado River.**

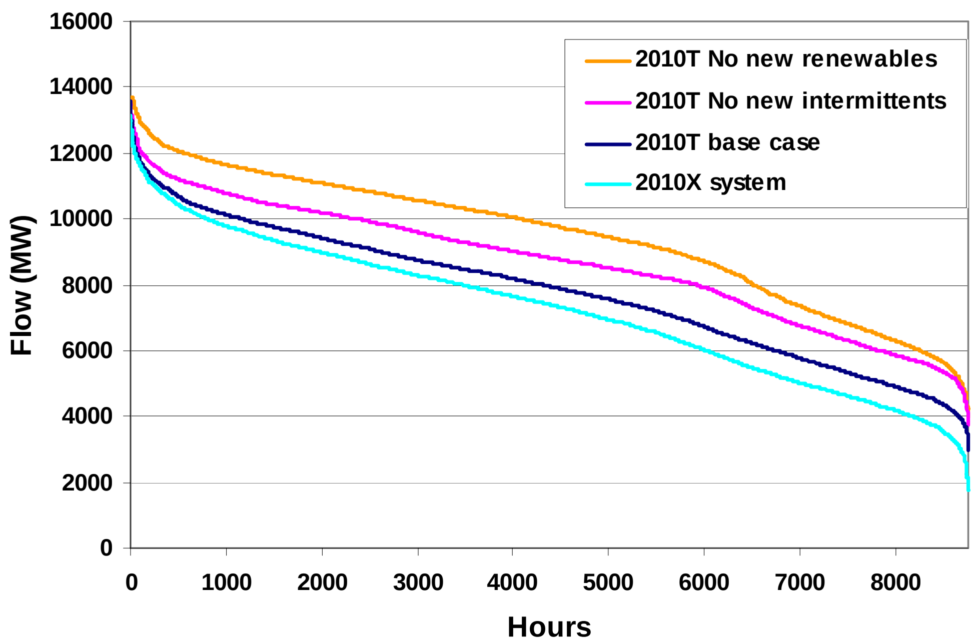


**Figure 120. Transmission Flow Duration Curves – Total SCIT (Southern California Import Transmission).**

Figure 121 shows the flow duration curves for the California-Oregon Interface for the base case and without the addition of the new intermittent generation. Although the total shift was small there was concern that the variability of the intermittent generation might introduce significant swings in the power flows on this interface.

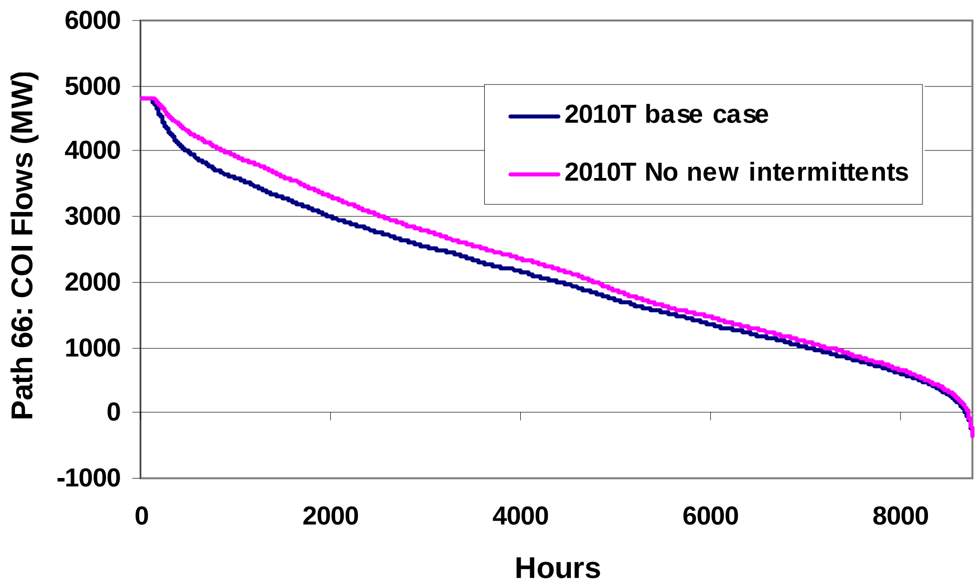


**Figure 121. Annual Duration Curve – Path 66: COI (2010T).**

Figure 122 shows the chronological flows on the interface for the first week in May. Although the imports into California are reduced when the intermittent generation is added there doesn't seem to be a significant change in the overall pattern.

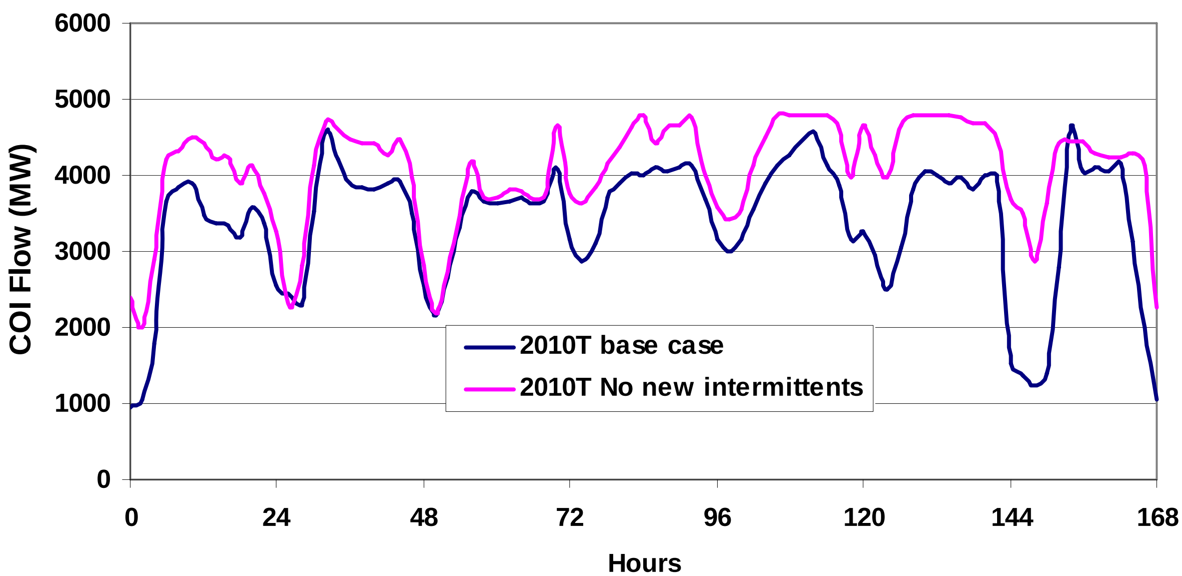


**Figure 122. Path 66: COI Flows for One Week in May (2010T).**

The hourly change in flows was calculated for the two curves in Figure 122 for the entire year and the values were sorted from high to low and displayed in Figure 123. From these curves it can be seen that there is no appreciable difference in the variability in the line flows due to the introduction of the intermittent generation.

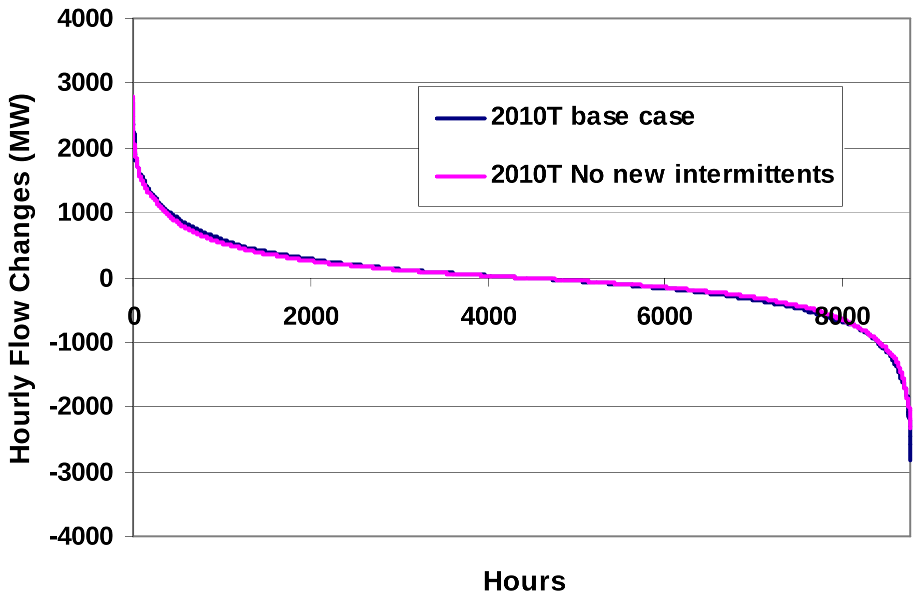


**Figure 123. Annual Duration Curve for Hourly Flow Changes on Path 66: COI (2010T).**

## 4.7. Observations

The introduction of any new generation into California will impact the cost of energy as reflected in the spot prices not only within California but throughout WECC. This is particularly true of renewable generators that tend to enter the market as "price takers" (even though the price paid for the energy is not zero). The impacts were generally rather moderate, although they could be more severe in some hours, with the significant drop in spot prices indicating that the system is running low on generation that can be maneuvered downward. The 2010T scenario had about 250 hours in the year with this more severe impact. The 33% penetration of renewables in the 2010X scenario increased this to about 500 hours.

Table 27 shows the average reductions in operating costs for all of WECC per MWh of the renewable generation. The decreased value of the wind and solar generation is due to their intermittent nature.

**Table 27. Average Variable Operating Cost Reductions per MWh of Renewable Energy (2010T).**

| | WECC ($/MWh) |
|---|---|
| **Biomass & Geothermal** | 39.48 |
| **Wind & Solar** | 29.90 |

Table 28 shows the average load payment reductions in both California and all of WECC per MWh of the renewable generation.

**Table 28. Average Load Payment Reductions per MWh of Renewable Energy (2010T).**

| | California ($/MWh) | WECC ($/MWh) |
|---|---|---|
| **Biomass & Geothermal** | 8.97 | 19.66 |
| **Wind & Solar** | 11.41 | 28.86 |

The non-renewable generators have their revenue reduced from two sides. The system spot prices in general have decreased so that they receive less revenue for each MWh of energy produced and in addition the amount of energy that they are producing has been reduced due to displacement by the renewable generation. Table 29 shows the impact in California and all of WECC for each type of renewable generation.

**Table 29. Average Non-Renewable Generator Revenue Reduction per MWh of Renewable Energy (2010T).**

| | California ($/MWh) | WECC ($/MWh) |
|---|---|---|
| **Biomass & Geothermal** | 23.98 | 69.17 |
| **Wind & Solar** | 17.78 | 47.42 |

It is of critical importance that the intermittent renewable generation be centrally forecasted and *published* in the day ahead market along with the load forecast in order that the market can properly respond to the intermittent generation. The impact of ignoring the intermittents in the commitment process was an order of magnitude greater than the impact of the displacement when they were properly accounted for, as summarized in Table 30.

**Table 30. Annual Load Payment Reductions from Intermittent Generation (2010T).**

| | California ($ Millions) | WECC ($ Millions) |
|---|---|---|
| **Wind & Solar with an estimated forecast** | 240 | 607 |
| **Ignoring Wind & Solar forecast in the commitment process** | 2231 | 6330 |

The addition of renewable generation reduced the total emissions throughout WECC. Table 31 shows the average emission reductions in WECC per MWh of renewable generation.

**Table 31. Average Annual Emission Reductions in WECC per MWh of Renewable Generation (2010T).**

| | NOx (lbs/MWh) | SOx (lbs/MWh) | CO2 (lbs/MWh) |
|---|---|---|---|
| **Biomass & Geothermal** | 130 | 10 | 830 |
| **Wind & Solar** | 117 | 46 | 810 |

In general it was shown that the energy displacement both inside California and throughout WECC was predominantly on the combined cycle generation. Roughly 40% of the displaced energy fell on units within California and 60% displaced imports coming from the rest of WECC. The hydro generation within California was adjusted based on the day ahead forecast for the intermittent generation. In the 2010T scenario, over 7500 MW of Wind generation only introduced shifts of roughly +/- 1500 MW in the hydro operation. Some hydro schedules outside of California were affected but the bulk of the modifications occurred in state. Historical operation indicated that these shifts should be well within the capability of the system most of the time. Pumped storage hydro operation increased as additional renewable generation was added but there didn't appear to be a need for additional PSH capacity. The exception to this might occur if the conventional hydro is severely constrained. In that case, the PSH activity increased significantly.

Overall ,with proper application of existing technology, using the existing and planned infrastructure and with appropriate policy changes to encourage flexibility in operation, there was not any significant operational problems identified at the hourly level to the introduction of renewable energy penetrations of up to 33%.

# 5.0 Quasi-Steady State Analysis

The statistical and production simulation analyses provided a broad view of the impact of significant intermittent (wind and solar) generation on system performance. They covered a range of time scales, from minute-to-minute to hourly as well as daily, seasonal and annual. In contrast, the quasi-steady-state (QSS) analysis consists of detailed time simulations of specific 3-hour periods. It is designed to illustrate key aspects of system performance and potential mitigation measures within the broader context of the statistical and production simulation analyses. As such, the QSS analysis is tightly linked to both of these analyses. For example, the QSS study scenarios were selected on the basis of the statistical analysis, and the QSS boundary conditions were set by the production simulation analysis.

The data, methods, assumptions, study scenarios and results for the QSS analysis are described in the following subsections. All QSS analysis was performed using GE's PSLF (Positive Sequence Load Flow) software package.

## 5.1. Overview of Method

The primary objectives of the QSS analysis were to evaluate the impact of significant intermittent generation on load following (5-minute time scale) and regulation (1-minute time scale) requirements within California.

This was accomplished by performing time simulations consisting of a series of power flow solutions to simulate California system performance on a minute-by-minute basis over selected 3-hour intervals. Each power flow in the series represented system conditions at a particular minute of the simulation. All California loads varied from minute to minute, all California wind project power outputs varied from minute to minute, and all California solar project outputs varied from minute to minute. Any power necessary to balance total California generation and load in the 1-minute time frame was provided by a proxy AGC unit. The power output of this proxy unit approximated the amount of regulation required of all units on AGC between 5-minute redispatches of the system.

At 5-minute intervals, a simplified economic dispatch was performed to meet the following objectives:

- Update the hour-ahead schedule for each designated California load following unit based on a perfect load and solar generation forecast, and a persistence-based wind generation forecast (i.e., the next hour will be the same as the current hour)
- Redistribute the power from the proxy AGC unit onto the designated load following units

A subset of all California units participated in this load following. Ramp rate limits (MW/minute) and absolute power limits (maximum and minimum MW) were respected on each unit. The identification of these units, and how they share load following duty, is discussed in Section 5.1.3.

The results of each 3-hour QSS simulation included a variety of performance metrics, as well as total California load, total California wind generation, total California solar generation, total power output of all units controlled by the economic dispatch, and selected interface flows.

### 5.1.1. Study Periods

The QSS study periods were selected based upon the hourly statistical analysis. The primary objective was to identify challenging, but credible, system conditions. Therefore, the hourly statistical analysis was used to identify study periods with any of the following characteristics:

- Large 1-hour and 3-hour changes in system load
- Large 1-hour and 3-hour changes in wind and solar generation
- High levels of wind and solar generation
- High levels of wind and solar penetration
- Low load levels

Three primary study periods were chosen - a July morning with both a load increase and a net decrease in wind and solar generation, a May night with both a low load level and high wind penetration, and a June evening with both a load decrease and a significant increase in wind generation. Additional characteristics of these study periods are shown in Table 32.

**Table 32. Characteristics of QSS Study Periods.**

| | July Morning Load Increase | May Night Light Load | June Evening Load Decrease |
|---|---|---|---|
| Renewable Scenario | 2010T(1) | 2010X(2) | 2010X(2) |
| Load Year | 2004 | 2003 | 2004 |
| Time Period(3) | 5:00 – 8:00 am | 1:00 – 4:00 am | 4:00 – 7:00 pm |
| Initial Total Load | 34,300 MW | 25,100 MW | 41,900 MW |
| Initial Total Wind | 3,400 MW | 10,200 MW | 2,200 MW |
| Initial Total Solar | 400 MW | 0 MW | 1,350 MW |
| Initial Wind and Solar Penetration(4) | 11% | 41% | 8% |
| Total Load Change | 8,200 MW | -700 MW | -2,700 MW |
| Total Wind Change | -2,100 MW | -600 MW | 4,400 MW |
| Total Solar Change | 450 MW | 0 MW | -900 MW |
| Total Net Change (L-W-S) | 9,850 MW | -100 MW | -6,200 MW |
| Final Total Load | 42,500 MW | 24,400 MW | 39,100 MW |
| Final Total Wind | 1,300 MW | 9,600 MW | 6,600 MW |
| Final Total Solar | 850 MW | 0 MW | 450 MW |
| Final Wind and Solar Penetration(4) | 5% | 39% | 18% |

Notes: (1) 2010T scenario includes about 7,500 MW of wind capacity and 1,900 MW of solar capacity.
(2) 2010X scenario includes about 12,500 MW of wind capacity and 2,600 MW of solar capacity.
(3) All times are in Pacific Standard Time.
(4) Instantaneous penetration was defined as total wind and solar generation (MW) divided by total load (MW).

System performance during each of these study periods will be illustrated in subsequent sections. The impact of various mitigation measures will also be addressed.

### 5.1.2. Input Data

Several types of data were used in the QSS analysis: power flow databases, individual wind project output profiles, individual solar project output profiles, a total California load profile, and individual unit ramp rate (MW/minute) capabilities.

DPC provided the power flows representing the renewable generation scenarios for 2010T and 2010X. The initial QSS simulation of the July morning study period used the 2010T renewable scenario, with about 7,500 MW of wind generation capacity and 1,900 MW of solar generation capacity. All other QSS simulations used the 2010X renewable scenario, with about 12,500 MW of wind capacity and 2,600 MW of solar capacity.

AWS Truewind provided 1-minute output profiles for each QSS study period. These profiles covered all existing and new wind farms identified in the 2010T renewable scenario, as well as a variety of additional profiles for future (e.g., 2020) projects. In general, a single profile was applied to each wind farm represented in the 2010T power flow. However, multiple profiles were applied to any large (e.g., 500 to 1,000 MW) wind projects represented as single equivalent units in the power flow. For example, a single equivalent 500 MW wind farm project at the Tehachapi 500kV bus was represented in the QSS analysis as five individual farms rated 100 MW, 100 MW, 102 MW, 103 MW, and 112 MW.

The 2010X renewable scenario accelerated many 2020 wind projects into the 2010 time frame. AWS Truewind profiles were assigned to these 2020 projects on the basis of wind region. Thus, a 2020 wind project in wind region 9 was assigned a wind profile from that region. The profiles were scaled, as needed, to better match the rating of large wind farms. For example, a 500 MW wind project in the 2010X renewable scenario was represented in the QSS analysis by four individual farms rated 110 MW, 110 MW, 125 MW and 155 MW and assigned AWS Truewind profiles scaled from the original 100 MW, 100 MW, 114 MW and 119 MW ratings.

Limited high resolution solar data was available. Therefore, the necessary 1-minute solar profiles were created from a variety of data sources. Profiles for the PV sites were created by superimposing 1-minute Golden, CO irradiation data on 15-minute PV data for 13 California zip codes. A discussion of the applicability of out-of-state solar data to California PV sites is provided in Appendix C. Profiles for the large Stirling solar facilities were created by superimposing 3-minute Desert Rock, NV irradiation data on hourly Stirling plant data. Profiles for all other concentrating solar plants were created by scaling the 1-minute profiles of the existing Sungen and Luz projects.

California ISO provided total load data for the study periods with 4-second resolution. This data was sampled at 1-minute intervals to create the necessary profiles for the QSS analysis. In that analysis, any change in total load from one minute to the next was spread across all California loads, proportional to the size of an individual load.

California ISO also provided confidential ramp rate data (MW/minute) for individual generating units. A weighted average ramp rate was calculated for each type of unit ( e.g., Steam, Hydroelectric) included in the data. This generic ramp rate, shown in Table 33, was then used in the QSS analysis.

**Table 33. Weighted Average Ramp Rate Data by Unit Type.**

| | %/Minute |
|---|---|
| Combined Cycle | 3.8 |
| Combustion Turbine | 13.5 |
| Hydroelectric | 22.3 |
| Steam | 3.1 |

Finally, California ISO provided data showing the amount of regulation procured on an hourly basis. The minimum procured during all of the QSS study periods was about 320 MW of up regulation and 320 MW of down regulation. This was a conservative assumption, as shown by the plots of procured regulation data in Section 6.0. The results of the QSS analysis associated with regulation were compared against these thresholds.

Many of the minimum generating unit outputs as defined by the power flows were zero. This does not reflect the reality that generating units have minimum load levels that must be respected. The minimum power output assumptions for California generation used in this study, by unit type, are shown in Table 34. The minimum output of combustion turbines was left at zero to emulate their fast start/stop characteristics.

**Table 34. Minimum Generation Output Level by Unit Type.**

| | % of Rating |
|---|---|
| Combined Cycle | 50 |
| Combustion Turbine | 0 |
| Hydroelectric | 20 |
| Steam | 25 |

### 5.1.3. Boundary Conditions

The results of the production simulation analysis were used to define the boundary conditions (i.e., initial and final system states) for each QSS study period. The power flows provided by DPC were modified to represent the desired initial and final conditions as specified by the production simulation analysis. These conditions included the dispatch of all generating units in WECC, individual area load levels, HVDC tie flows, and inter-area AC tie flows.

A comparison of the California generation dispatch between the initial and final power flows identified those units whose output changed over the study period. A subset of these units (e.g., those with a 3-hour change in dispatch of > 25MW) were used in the QSS economic dispatch model. Therefore, fewer units were assigned to load following in the QSS simulations than in the production simulation analysis. As a result, the QSS simulations were conservative compared to the expected capability of the California system.

Once the economic dispatch units were identified, each was assigned a participation factor for the QSS analysis. The participation factor allotted a fraction of the economic dispatch requirements (MW) to each identified unit. The allotted fraction was proportional to the change in generation dispatch observed on the unit in the production simulation results, compared to the total change in generation dispatch over the 3-hour study period. As an equation, the participation factor can be defined as follows:

$$PF = MW_i / MW_{total}$$

where: $MW_i$ = MW change on $i^{th}$ unit over 3-hour period

$MW_{total}$ = total MW change on all economic dispatch units over 3-hour period

The comparison of initial and final power flows also identified changes in HVDC tie flows and the level of California imports. In the QSS analysis, HVDC tie flows were ramped from the initial condition to the final condition. However, the 3-hour California import increases were ignored to ensure that all necessary in-state load following and regulation was performed by California units. The greater WECC system was, therefore, largely unchanged during a QSS simulation.

## 5.2. System Performance Examples

The results of the QSS analysis are discussed in this section. The analysis of the July morning study period is presented first. That discussion will focus on illustrating the QSS analysis procedure and defining the resulting performance metrics. The analyses of the May night and June evening study periods will follow. Those sections will focus on illustrating key aspects of system performance and potential mitigation measures.

### *5.2.1. July Morning Load Increase*

The July morning study period was evaluated under the 2010T renewable scenario, which includes about 7,500 MW of wind generation capacity at 98 sites and 1,900 MW of solar generation capacity at 12 concentrating solar plants and 136 PV sites. The load was derived from the 2004 data.

As shown in Table 32, this study period included a large increase in load (8,200 MW) combined with a net decrease in wind and solar generation (-1,650 MW). This results in a net load increase of about 9,850 MW. As context, note that the statistical analysis of three years of hourly data showed the largest 3-hour load increase was 10,900 MW, and about 1% of the 3-hour load increases were greater than 8,200 MW. The maximum 3-hour drop in wind generation over those three years of data was about -2,700 MW, and a 3-hour wind decrease greater than -2,100 MW occurred 17 times. Similarly, the maximum 3-hour net load (i.e., load minus wind minus solar) increase was 11,300 MW. A 3-hour net load increase greater than 9,850 MW occurred 20 times, and a 3-hour load only increase greater than 9,850 MW occurred 6 times.

The total load profile for the July morning study period is shown in Figure 124. The single largest 1-minute change in load is approximately -300 MW and occurs just past 7:30 am. This may represent a pumped storage hydro pump stopping. The total wind generation profile for this study period is shown in Figure 125, and the total solar generation profile is shown in Figure 126. These three figures provide an overview of the input to the QSS simulation. For load alone, the load following requirement was about 2,700 MW/hour (i.e., 8,200 MW/3 hours). With the net decrease in wind and solar generation, the load following requirement increased to about 3,300 MW/hour (i.e., 9,850 MW/3 hours).

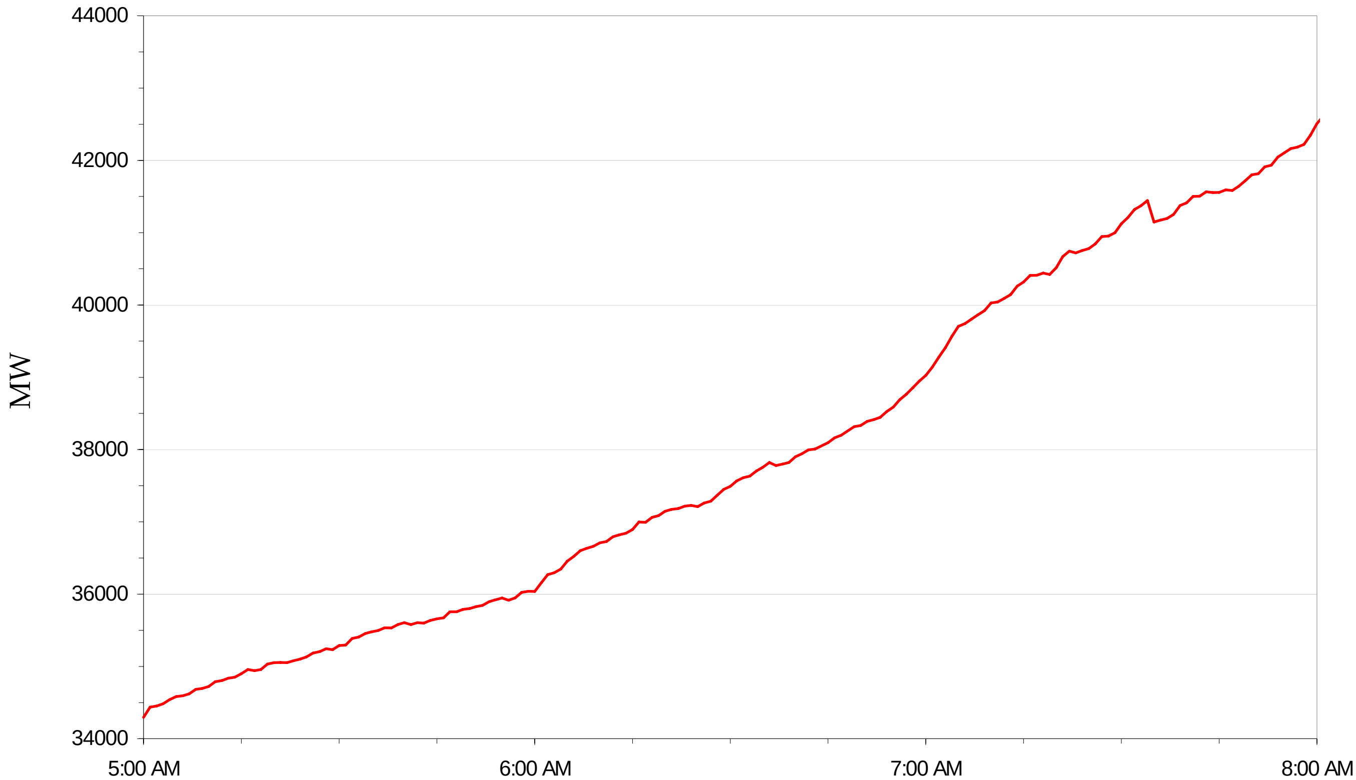


**Figure 124. Total California Load During the July Morning QSS Study Period.**

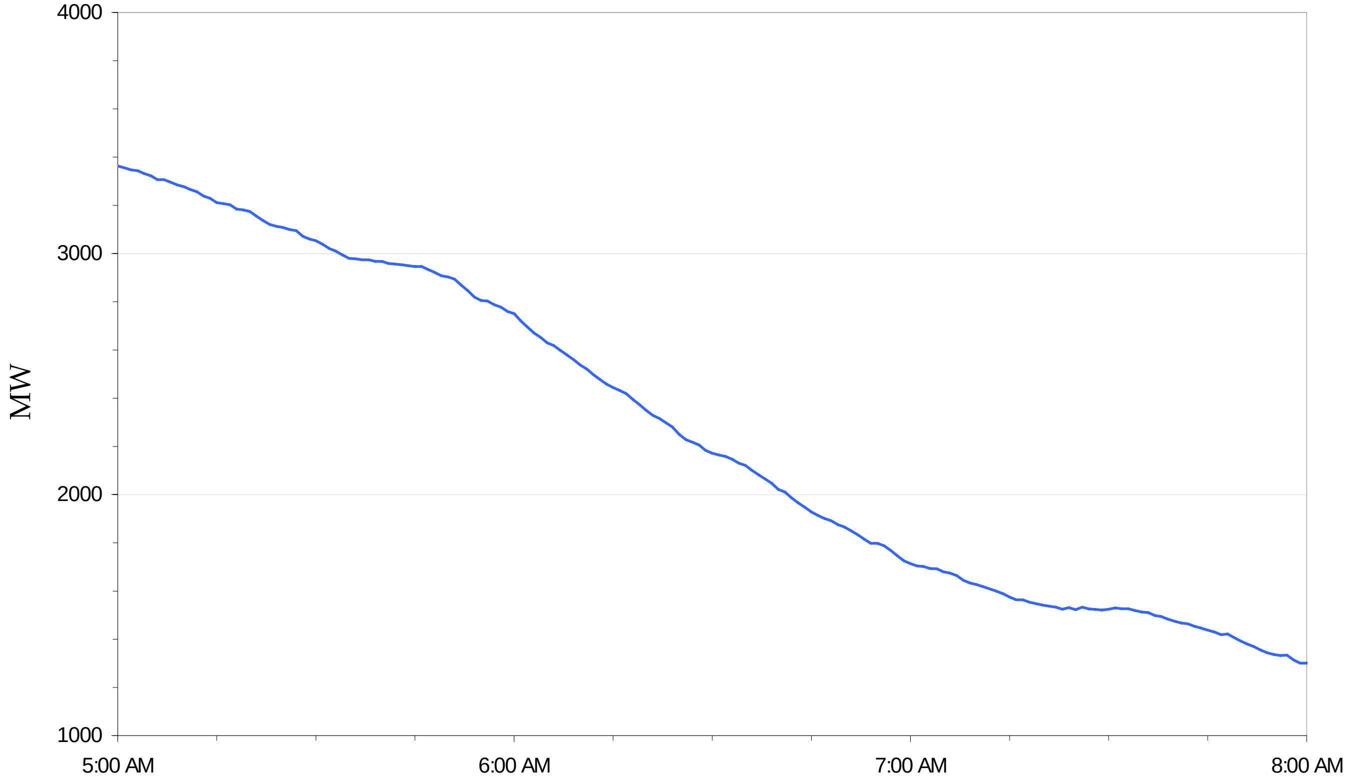


**Figure 125. Total California Wind Generation During the July Morning QSS Study Period.**

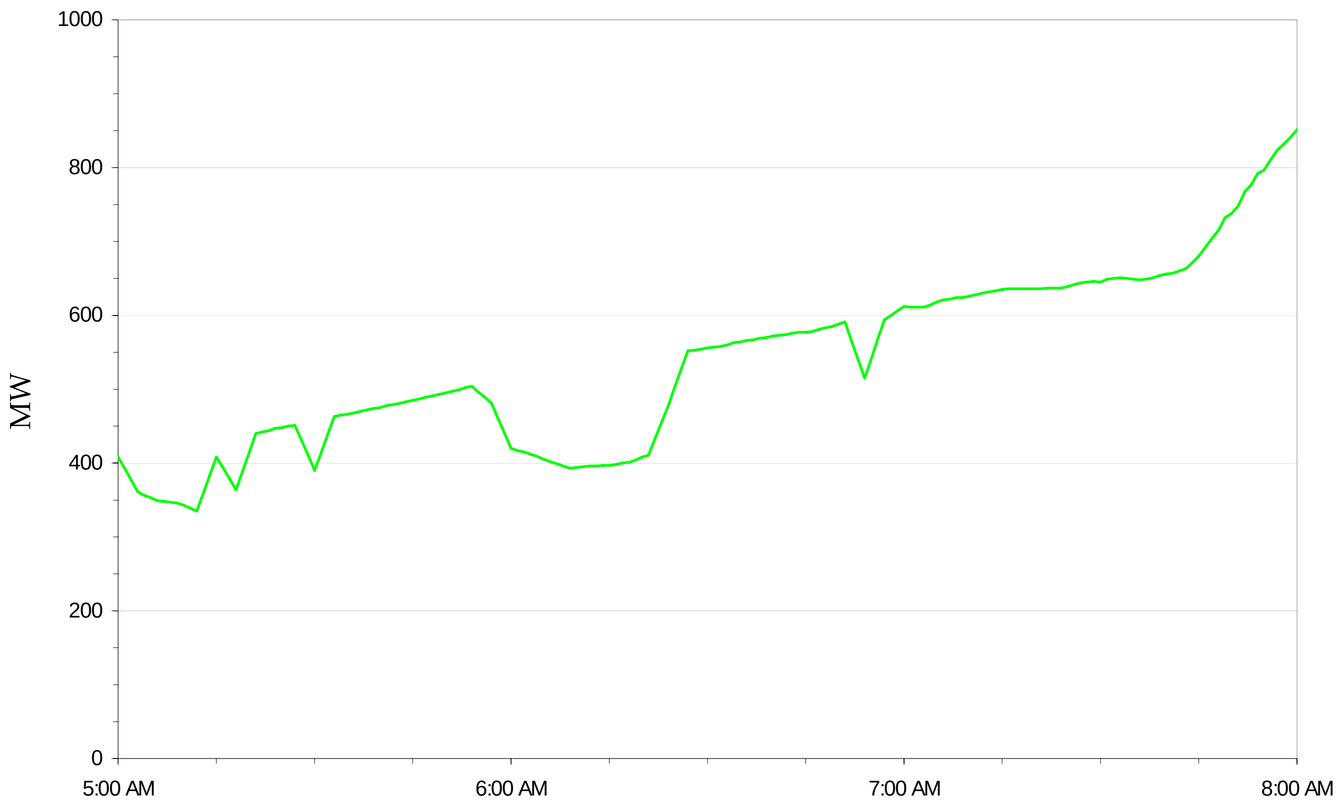


**Figure 126. Total California Solar Generation During the July Morning QSS Study Period.**

The output variables of the QSS analysis were divided into two categories. One group was associated with maneuverability, and measures the response of the balance-of-portfolio (i.e., non-renewable) generators to the changing load, wind and solar conditions. The other group was associated with performance, and measures net load (e.g., load minus wind minus solar) variability, as well as the resulting regulation and load following requirements. All California load, wind and solar generation are rolled into these metrics. However, only the subset of all other California generating units that participates in the QSS economic dispatch is included in the metrics. These units will be called economic dispatch or ED units throughout the remainder of this section.

Specifically, the QSS maneuverability variables are defined as follows:

- PUPtot = Remaining range of ED units to increase output = $\Sigma\ (P_{imax} – P_i)$
- PDNtot = Remaining range of ED units to decrease output = $\Sigma\ (P_{imin} – P_i)$
- Pmntot = Minimum power of ED units = $\Sigma\ P_{imin}$
- Pmxtot = Maximum power of ED units = $\Sigma\ P_{imax}$
- Sum ED MW = Output of ED units = $\Sigma\ P_i$
- RUPtot = Remaining rate capability of ED units to ramp up = $\Sigma$ ($Rate_i$, if $P_i < P_{imax}$)
- RDNtot = Remaining rate capability of ED units to ramp down = $\Sigma$ ($-Rate_i$, if $P_i > P_{imin}$)

where

- $P_i$ = Real power output of the $i^{th}$ ED unit (MW)
- $P_{imax}$ = Maximum real power output of the $i^{th}$ ED unit (MW)
- $P_{imin}$ = Minimum real power output of the $i^{th}$ ED unit (MW)
- $Rate_i$ = Weighted average ramp rate of the $i^{th}$ ED unit (MW/minute)

The first five maneuverability variables (PUPtot, PDNtot, Pmntot, Pmxtot, Sum ED MW) are in units of MW. The last two variables (RUPtot, RDNtot) are in units of MW/minute.

The maneuverability results for the July study period are shown in Figure 127. The green line represents Pmxtot, which is a constant 15,000 MW during the QSS simulation. Similarly, the lavender line represents Pmntot, which is zero throughout. The black line shows Sum ED MW, or the total output of the ED units. As the net load increases over this 3-hour period, the output of the ED units also increases. The remaining up range available on those units (PUPtot) is represented by the red line. Note that it decreases as the output of the units increases. Conversely, the remaining down range (PDNtot), represented by the turquoise line, increases as the total output increases. The final two traces represent the up (RUPtot, yellow line) and down (RDNtot, pink line) ramp rate capability of the ED units. As with the up range, the up ramp rate capability is reduced as the output increases. As with the down range, the down ramp rate capability is increased as the output increases.

The sign convention is such that up range or ramp capability is shown as a positive number, and down range or ramp capability is shown as a negative number.

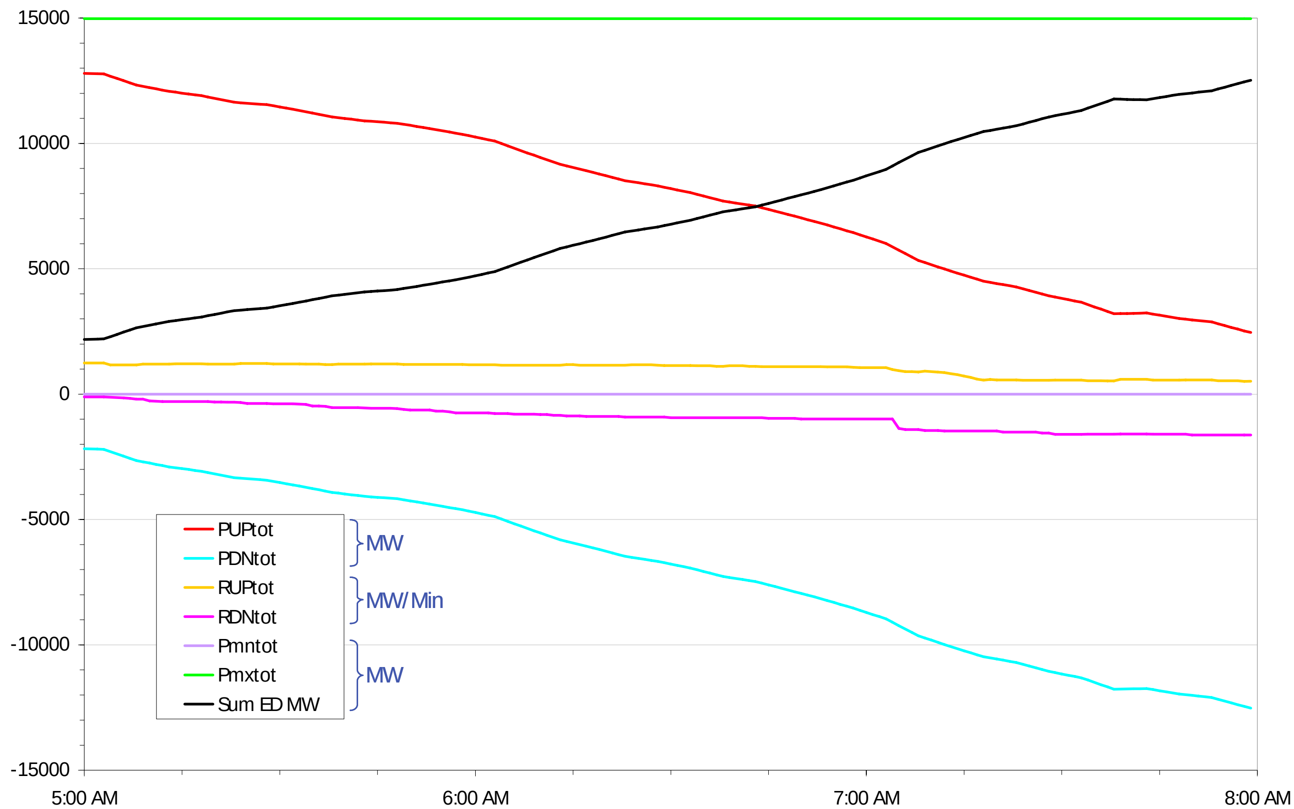


**Figure 127. Maneuverability Variables During the July Morning QSS Study Period.**

The QSS performance variables are defined as follows:

- Delta L-W-S = Change in total load minus wind generation minus solar generation
- Delta ED MW = Total change in ED unit output required to follow load
- Preg = Total regulating power necessary to balance load and generation

The first two performance variables (Delta L-W-S, Delta ED MW) are in units of MW/minute. The other variable (Preg) is in units of MW.

The performance results for the July study period are shown in Figure 128. The blue trace shows the minute-to-minute change in net load (Delta L-W-S). The green trace shows the amount of power required on a 1-minute basis to balance generation and load (Preg). The yellow lines (Reg Up, Reg Down) show the minimum regulation procured during this study period. Note that the largest change in net load, as well as the largest need for regulation, coincides with the 300 MW decrease in load observed just after 7:30 am in Figure 124. A second large regulation requirement occurs just after 7:00 am. This is associated with a persistent increase in Delta L-W-S , driven by a short term increase in the slope of the load profile.

The pink line shows the total change in ED unit output (Delta ED MW) required to follow load and accommodate the required minute-minute regulation. Since the economic dispatch is performed every 5 minutes, the Delta ED MW signal is constant for each successive 5-minute period. Initially, the total increase in ED unit output is less than 10 MW/minute. It is almost always positive during this morning load rise, and peaks at about 135MW/minute just after 7am.

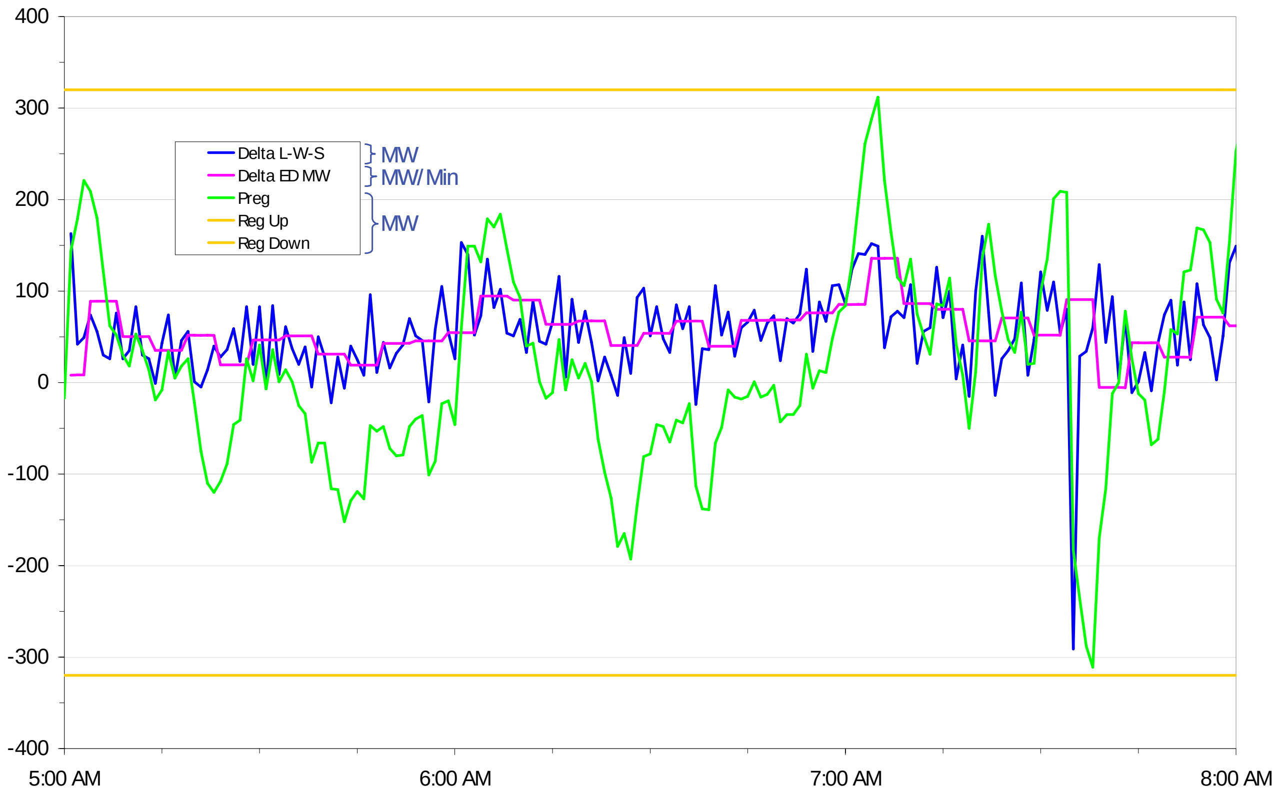


**Figure 128. QSS Performance Variables During the July Morning QSS Study Period.**

As previously noted, the production simulation analysis defined the boundary conditions for the QSS analysis. As such, the ED units were identified on an economic basis. The total change in ED unit output, by type, is shown in Figure 129 for the July study period. By definition, each of these traces starts at zero. The blue line represents the total change in all hydroelectric ED unit output, and the pink line represents the total change in all combined cycle ED unit output. This case shows that most of the load-following is performed by combined-cycle plants, followed by hydroelectric units.

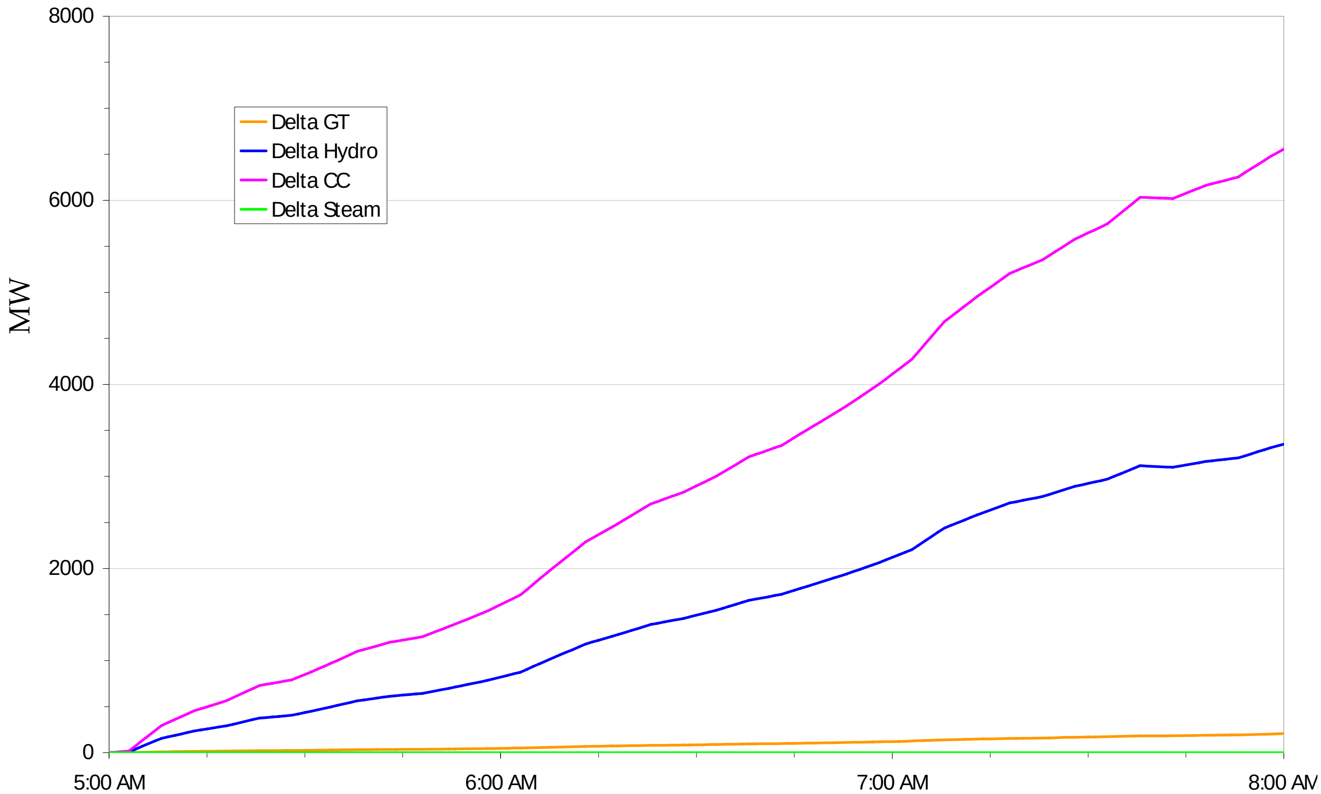


**Figure 129. Economic Dispatch Unit Change During the July Morning QSS Study Period.**

An additional sensitivity case was performed to evaluate the impact of wind and solar variability on system performance. For this QSS simulation, all wind and solar plants were held constant at their initial values during the 3-hour study period. Constant wind and solar generation is equivalent to any non-dispatchable generation (e.g., biomass, nuclear).

Cross plots of the sensitivity case results with the primary results are shown in Figure 130 and Figure 131. In both figures, the blue line represents the sensitivity case with constant intermittent renewable output, and the yellow line represents the primary case with variable wind and solar output.

Figure 130 shows the impact of intermittent renewable variability on the duty imposed on the proxy AGC unit. These results indicate that the regulation duty is due primarily to load variation, but is offset up by the net decrease in wind and solar power over 3 hours.

Figure 131 shows the impact of intermittent renewable variability on the economic dispatch and load following requirements. These results show that the load following duty is increased from an average of about 50 MW/minute to about 60 MW/minute due to the net decrease in wind and solar power.

In general, the July morning QSS analysis shows that an economically rational unit commitment and dispatch provides adequate load-following capability.

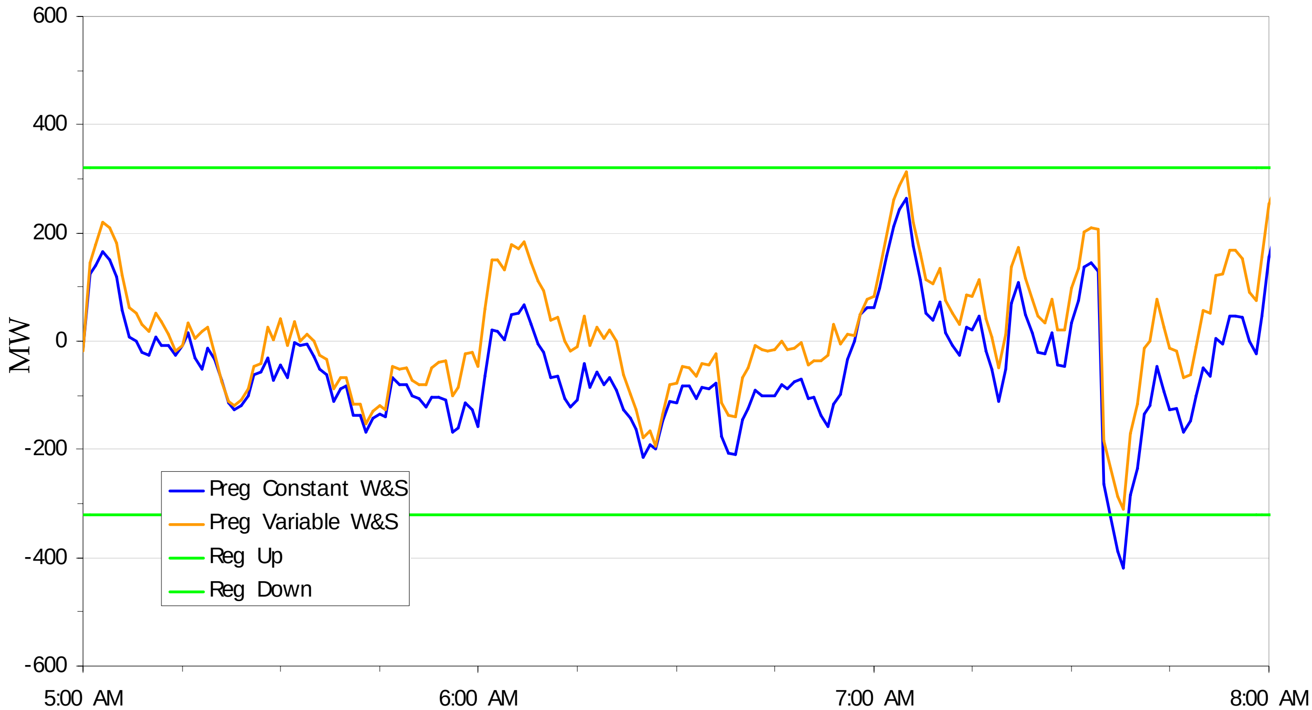


**Figure 130. Impact of Intermittent Variability on Regulation Duty During July QSS Study Period.**

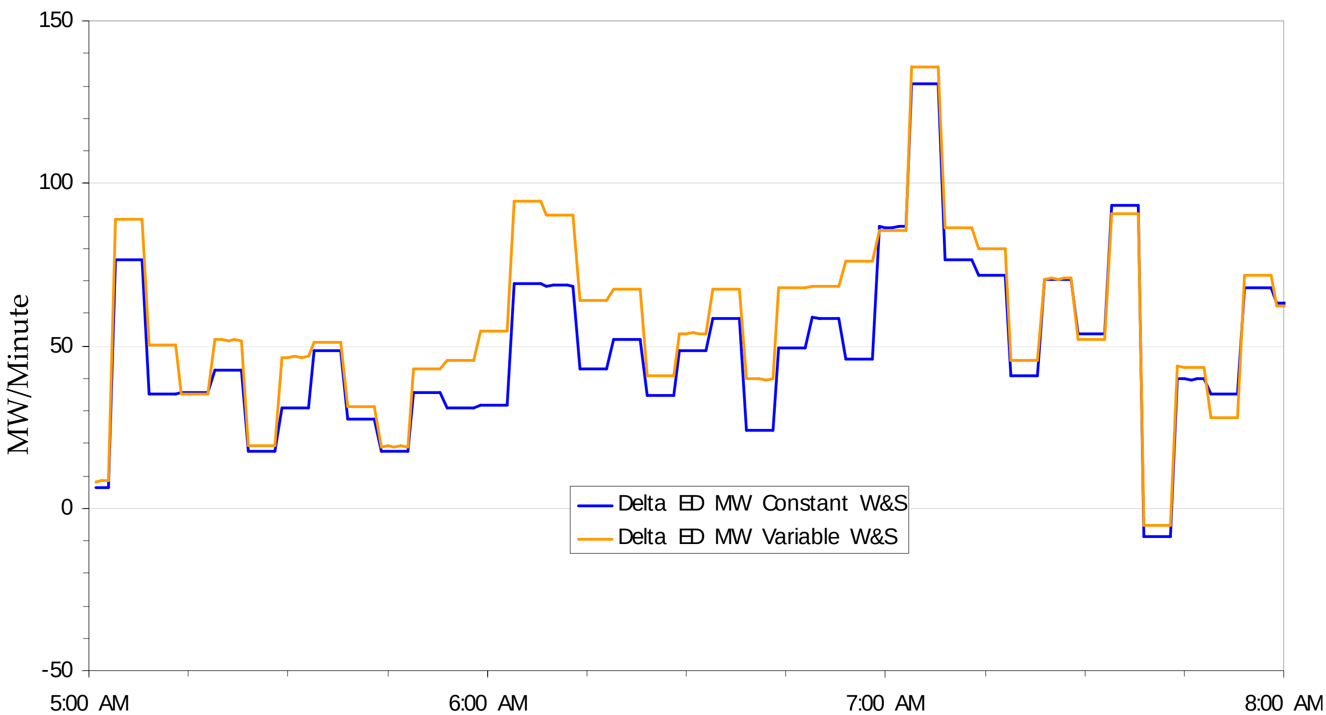


**Figure 131. Impact of Intermittent Variability on Economic Dispatch and Load Following Duty During July QSS Study Period.**

### 5.2.2. May Night Low Load Level

The May night study period was evaluated under the 2010X renewable scenario, which includes about 12,500 MW of wind generation capacity at 142 sites and 2,600 MW of solar generation capacity at 42 concentrating solar plants and 128 PV sites. The load was derived from the 2003 data. As described in Section 5.1.3, the units available in the QSS analysis are a subset of both the total number of units in California as well as the units available in the production analysis. Thus, the analysis was conservative.

As shown in Table 32, this study period represented a relatively light load condition (25,100 MW) with a high level of instantaneous wind penetration (10,200 MW or 41%). Neither the load nor the wind changed significantly over the 3-hour study period. As context, note that the statistical analysis of three years of hourly data showed the peak wind generation output was 11,500 MW, and wind generation was greater than 10,000 MW for less than 1% of the hours. The average hourly intermittent penetration at light load was about 29%, and the peak hourly intermittent penetration was about 39%.

The total load profile for the May night study period is shown in Figure 132. Several load steps greater than +/- 200 MW are observed. These are likely due to switching pumped storage hydro facility pumps, or other large loads. A later sensitivity case will investigate system response without these load steps, since they may be predictable and/or scheduled. The total wind generation profile for this study period is shown in Figure 133. There is no solar generation profile at night. These two figures provide an overview of the input to the QSS simulation.

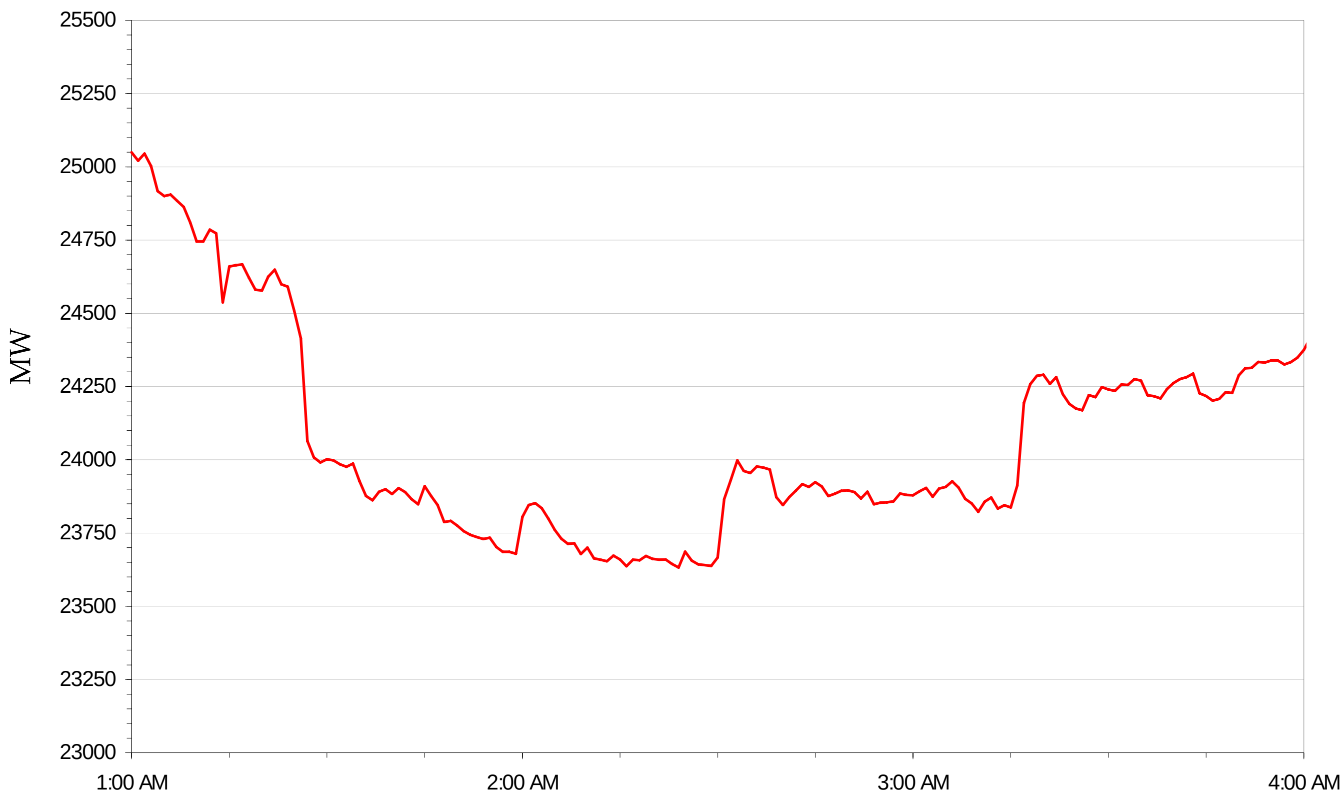


**Figure 132. Total California Load During the May Night QSS Study Period.**

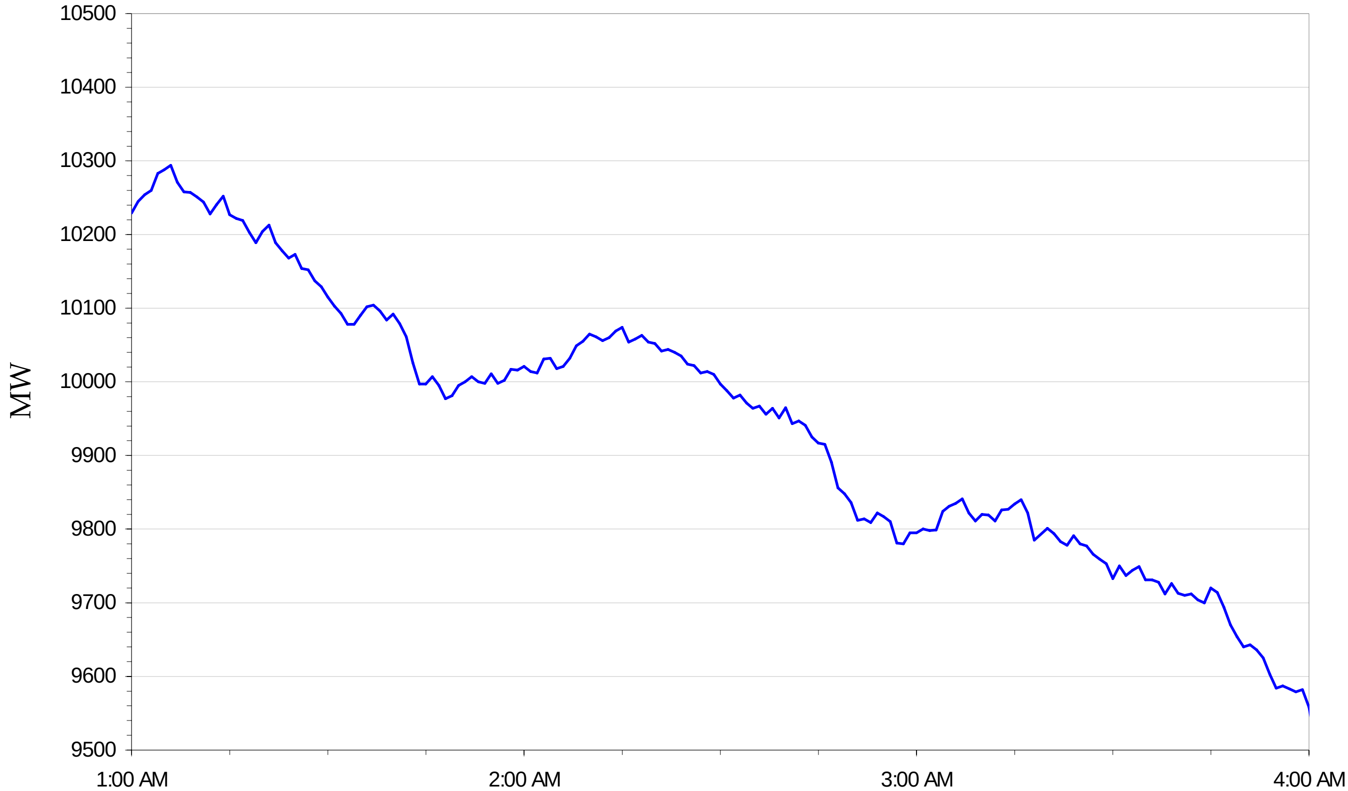


**Figure 133. Total California Wind Generation During the May Night QSS Study Period.**

The QSS maneuverability variables (defined in Section 5.2.1) for the May study period are shown in Figure 134. The green line represents Pmxtot, which is a constant 5,500 MW during the QSS simulation. Similarly, the lavender line represents Pmntot, which is constant at about 1,100 MW. The up ramp rate capability (RUPtot) of the ED units is represented by the yellow line, and the down ramp rate capability (RDNtot) is represented by the pink line. Similarly, the remaining up range available on the ED units (PUPtot) is represented by the red line, and the remaining down range (PDNtot) is represented by the turquoise line. The black line shows the total actual output of the ED units (Sum ED MW). As the net load decreases over this 3-hour period, the output of the ED units also decreases. At about 1:30 am, the ED units have run out of down ramp rate capability. At about 1:45 am, the ED units have run out of down range. Thus, all down maneuverability has been exhausted. After about 3:15 am, the net load has increased such that some down maneuverability is recovered.

The QSS performance results (also defined in Section 5.2.1) for the May study period are shown in Figure 135. The blue trace shows the minute-to-minute change in net load (Delta L-W-S). The green trace shows the amount of power required on a 1-minute basis to balance generation and load (Preg). The yellow lines (Reg Up, Reg Down) show the minimum regulation procured during this study period.

Two observations can be made. First, the large steps in load have more significant impact on the regulation duty (Preg) than the variability of load and wind. This is observed in the large changes in Preg at about 1:30 am, 2:30 am and 3:15 am.

Second, insufficient down capability (both range and ramp rate) shifts load following duty to regulation, which may then become exhausted. This in turn may result in a violation of CPS2 criteria. The shift is observed between 1:30 am and 2:30 am with the persistently high level of negative output from the AGC proxy unit while the load following capability (Delta ED MW) is zero.

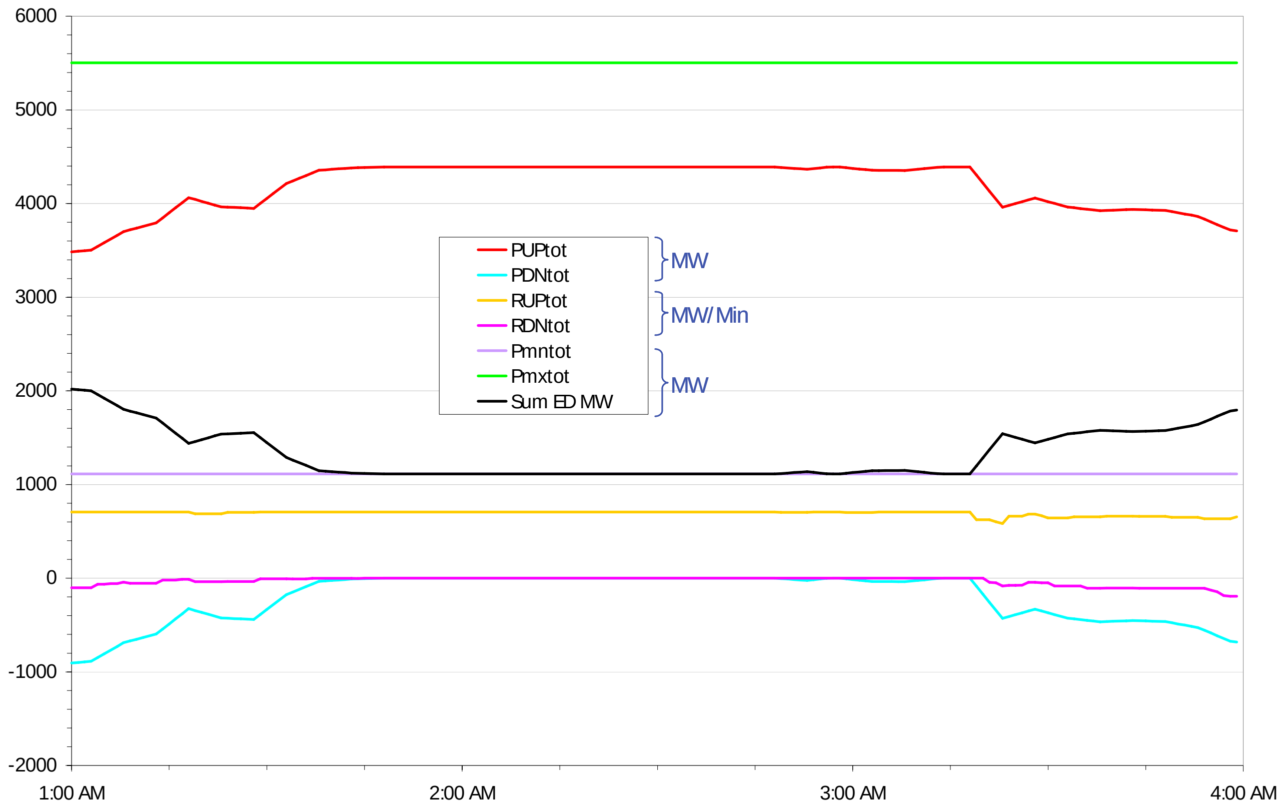


**Figure 134. Maneuverability Variables During the May Night QSS Study Period.**


**Figure 135. Performance Variables During the May Night QSS Study Period.**

### *Increase Maneuverable Generation*

A sensitivity case was performed to evaluate the impact of increasing the maneuvering capability of the balance-of-portfolio generation by changing the generation commitment. This was accomplished by replacing 2,200 MW of base load generation with 2,200 MW of combined-cycle generation.

The QSS maneuverability variables for this sensitivity case are shown in Figure 136. The green line represents Pmxtot, which is a constant 8,400 MW during the QSS simulation. Similarly, the lavender line represents Pmntot, which is constant at about 2,600 MW. The up ramp rate capability (RUPtot) of the ED units is represented by the yellow line, and the down ramp rate capability (RDNtot) is represented by the pink line. Similarly, the remaining up range available on the ED units (PUPtot) is represented by the red line, and the remaining down range (PDNtot) is represented by the turquoise line. The black line shows the total actual output of the ED units (Sum ED MW). As the net load decreases over this 3-hour period, the output of the ED units also decreases. Unlike the original case (Figure 134), however, neither down range nor down ramp rate capability is exhausted. Therefore, the load following requirements are not shifted to the AGC proxy unit.

This is confirmed by the QSS performance results shown in Figure 137. The blue trace shows the minute-to-minute change in net load (Delta L-W-S). The green trace shows the amount of power required on a 1-minute basis to balance generation and load (Preg). The yellow lines (Reg Up, Reg Down) show the minimum regulation procured during this study period. Unlike the original case (Figure 135), the proxy AGC unit output (Preg) is largely within the procured regulation range. The excursions beyond those thresholds are due to large steps in load at about 1:30 am, 2:30 am, and 3:15 am.

This sensitivity case shows that replacing non-maneuverable generation with maneuverable generation in the balance-of-portfolio (i.e., non-renewable generation) effectively mitigates loss of both down range and down ramp rate capability under light load conditions.

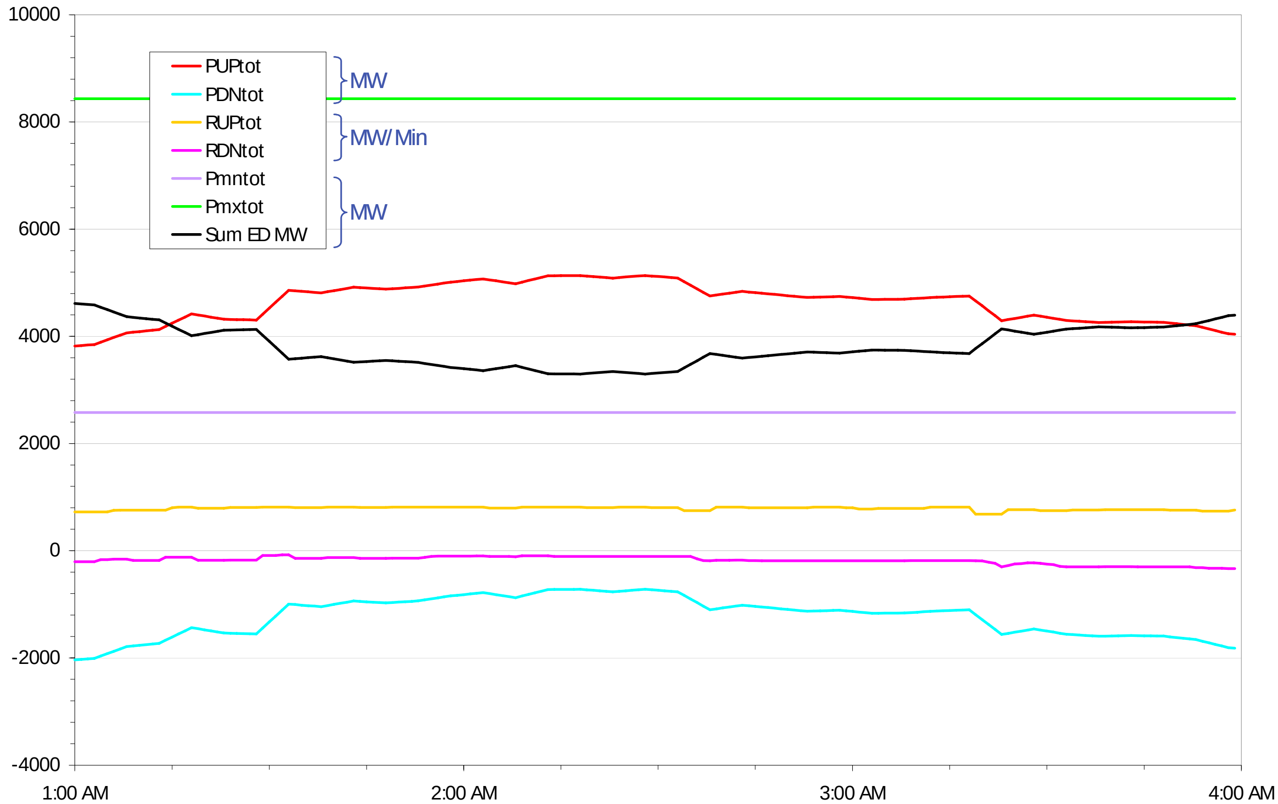


**Figure 136. Maneuverability Variables for a May Night with More Combined–Cycle Plants.**

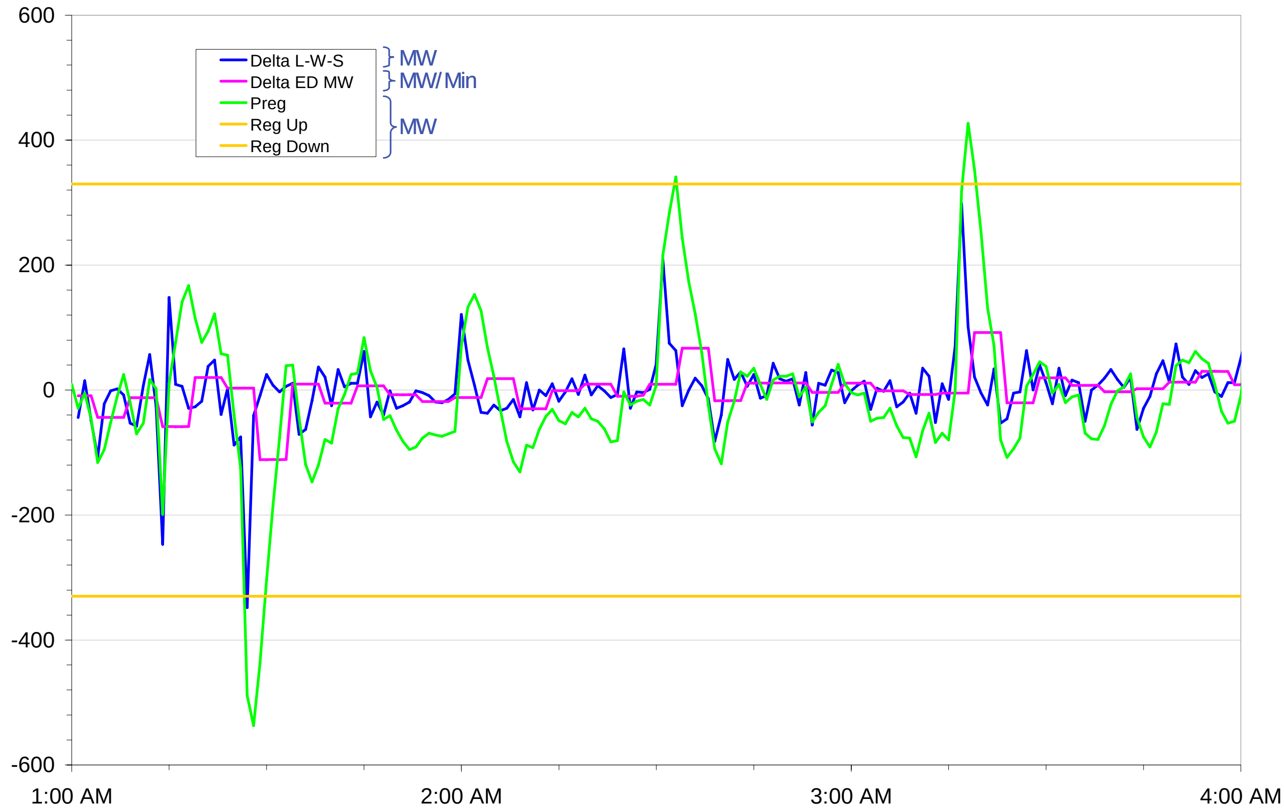


**Figure 137. Performance Variables for a May Night with More Combined–Cycle Plants.**

Another sensitivity case was performed to evaluate the impact of wind variability on system performance. This QSS simulation again used the modified generation commitment with more maneuverable combined cycle plants available. In addition, all wind plants were held constant at their initial values during the 3-hour study period. As previously noted, constant wind generation is equivalent to any non-dispatchable generation.

Cross plots of this sensitivity case results with the previous results are shown in Figure 138 and Figure 139. In both figures, the blue line represents the sensitivity case with constant wind output, and the yellow line represents the modified commitment case with variable wind output.

Figure 138 shows the impact of wind variability on the duty imposed on the proxy AGC unit. These results confirm that the regulation duty is due primarily to load variation, but is increased by the variability associated with 10,000 MW of wind generation.

Figure 139 shows the impact of wind variability on the economic dispatch and load following requirements. These results show that the variability of wind increases the ED unit duty – both the MW/minute and the frequency of sign changes increase.

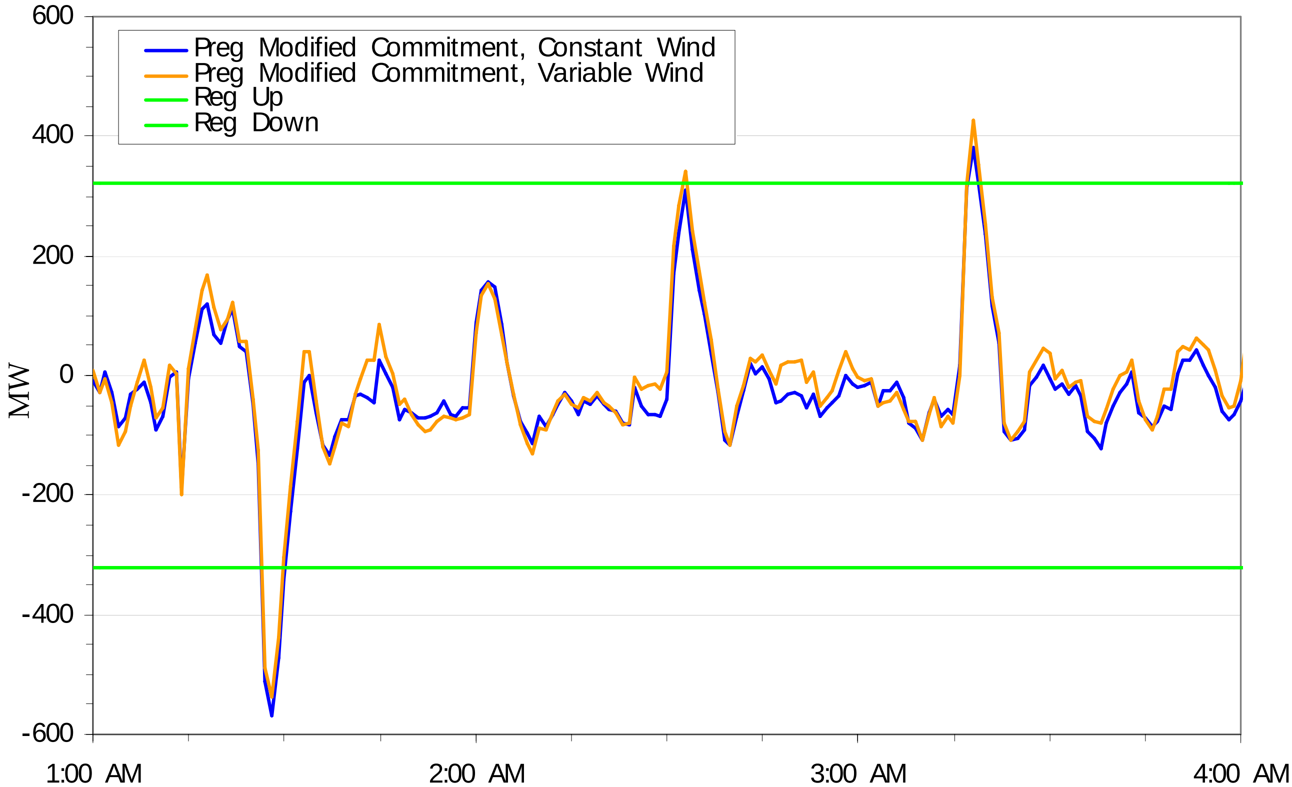


**Figure 138. Impact of Wind Variability on Regulation Duty During May QSS Study Period.**

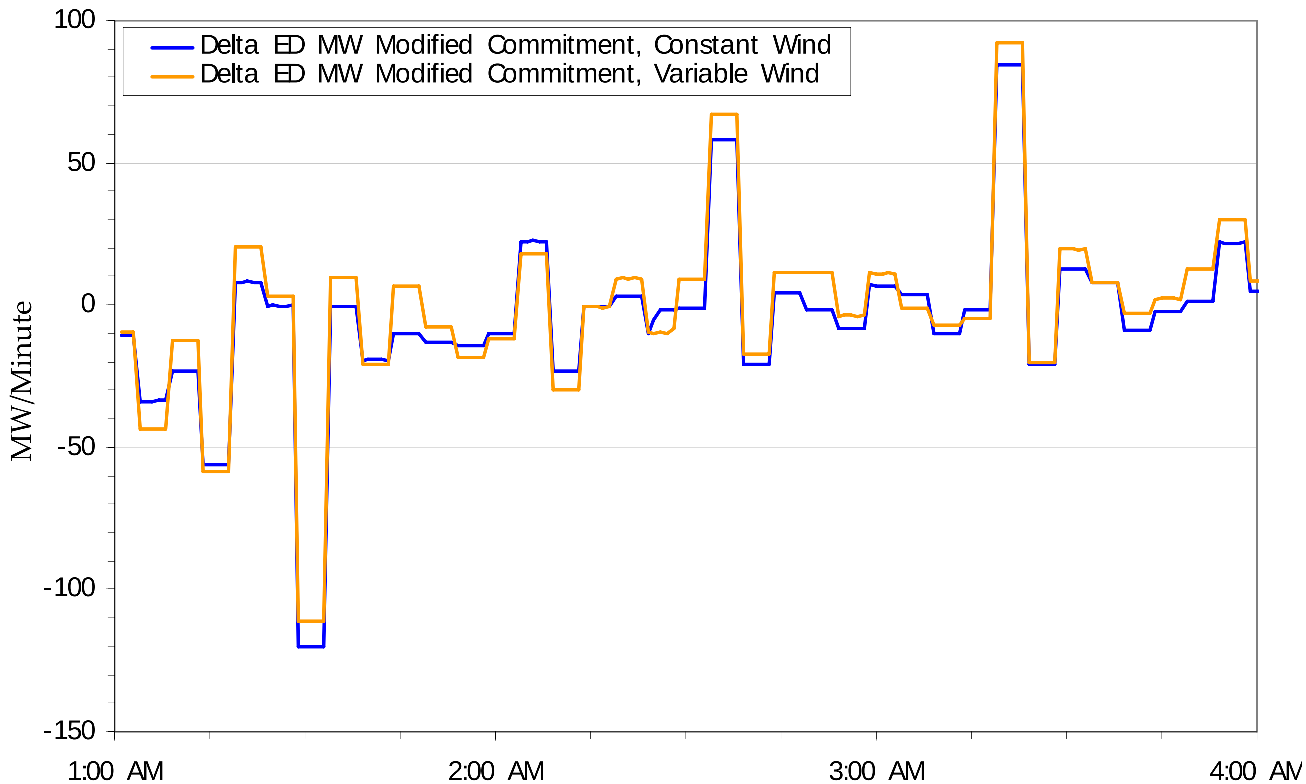


**Figure 139. Impact of Wind Variability on Economic Dispatch and Load Following Duty During May QSS Study Period.**

### *Temporary Curtailment of Wind Generation*

The previous section explored one mitigation method – modifying the generation commitment to ensure sufficient maneuverability. Another mitigation method, the temporary curtailment of wind generation, is examined in this section. The original May wind profile (blue line) and the curtailed wind profile (yellow line) are shown in Figure 140. For this illustration, the curtailment consisted of a relatively fast reduction in wind generation of about 500 MW over 5 minutes. This reduction was applied at about 1:15 am before all down maneuverability was exhausted in the original May simulation (Figure 134). Total wind production was curtailed for the next two hours. The curtailment was removed after some down maneuverability was recovered in the original May simulation at about 3:30 am. Wind farm output was allowed to increase over about 10 minutes back up to that available due to the prevailing wind. This temporary curtailment was implemented at all wind farms, with each reducing its output by a share of the 500 MW proportional to its rating. The wind energy lost during the curtailment was about 1,140 MWh out of about 30,000 MWh, or 3.8%, for this 3-hour period. As noted above, the statistical analysis of three years of hourly data showed total wind generation was greater than 10,000 MW for less than 1% of the hours. Hence, this is a rare occurrence.

Cross plots of the results from the curtailed wind simulation and the original wind simulation are shown in Figure 142 and Figure 141. In both figures, the blue line represents the case with the original wind profile, and the yellow line represents the case with the curtailed wind.

Figure 141 shows the impact of wind variability on the economic dispatch and load following requirements. The results from the original wind profile simulation show that all down maneuverability is lost between about 1:45 am and 2:45 am when the ED unit output is zero. Wind curtailment ensures that the remaining non-renewable generation maintains sufficient maneuverability to follow load, as shown by the non-zero ED unit output in that case.

Figure 142 shows the impact of wind variability on the duty imposed on the proxy AGC unit. Under the original wind profile, the lack of load following capability has shifted that duty to the proxy AGC unit. The case with wind curtailment has sufficient load following capability, so the regulation requirements are now largely between the procured regulation thresholds. As previously noted, the excursions are due to large changes in the load profile.

The results of these QSS simulations show that the curtailment of wind effectively mitigates loss of maneuverability under extreme light load, high wind conditions. Curtailment would also allow the wind plants to provide regulation.

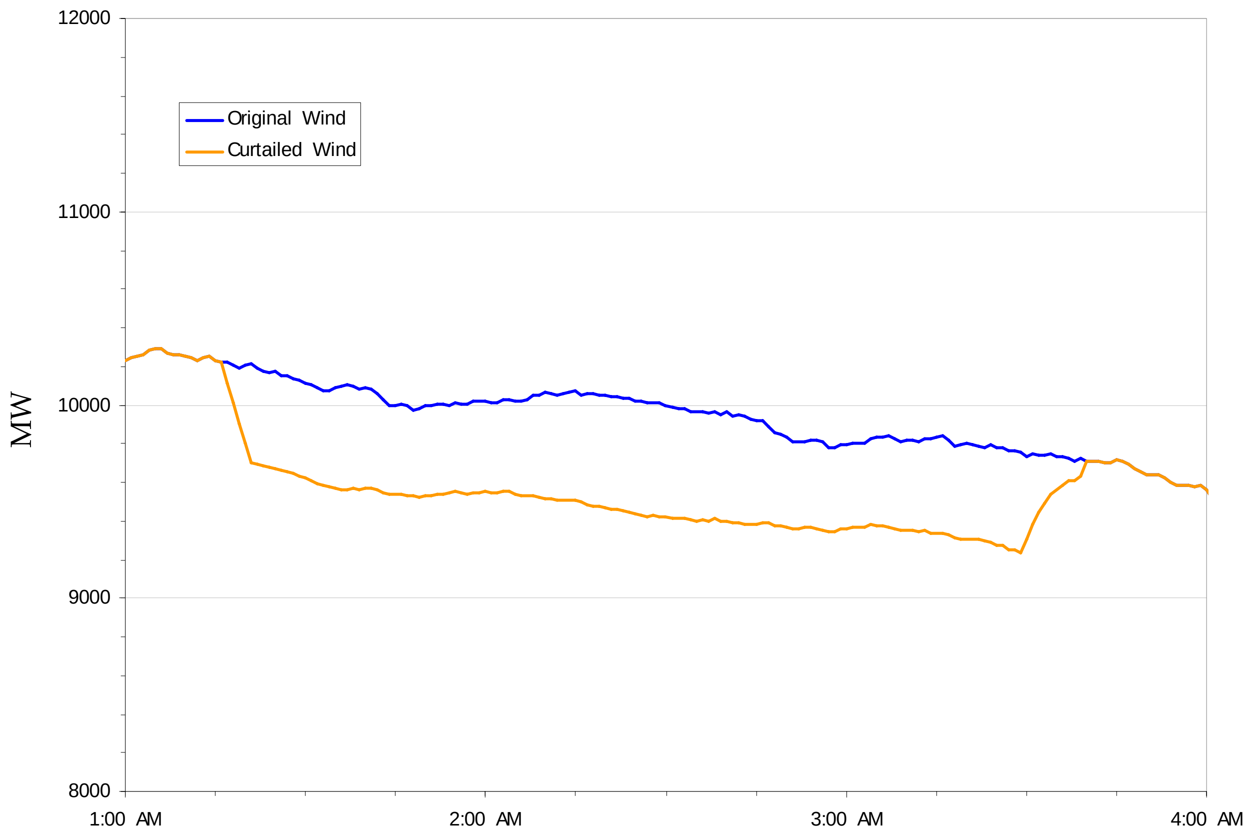


**Figure 140. Temporary Curtailment of Wind Generation.**

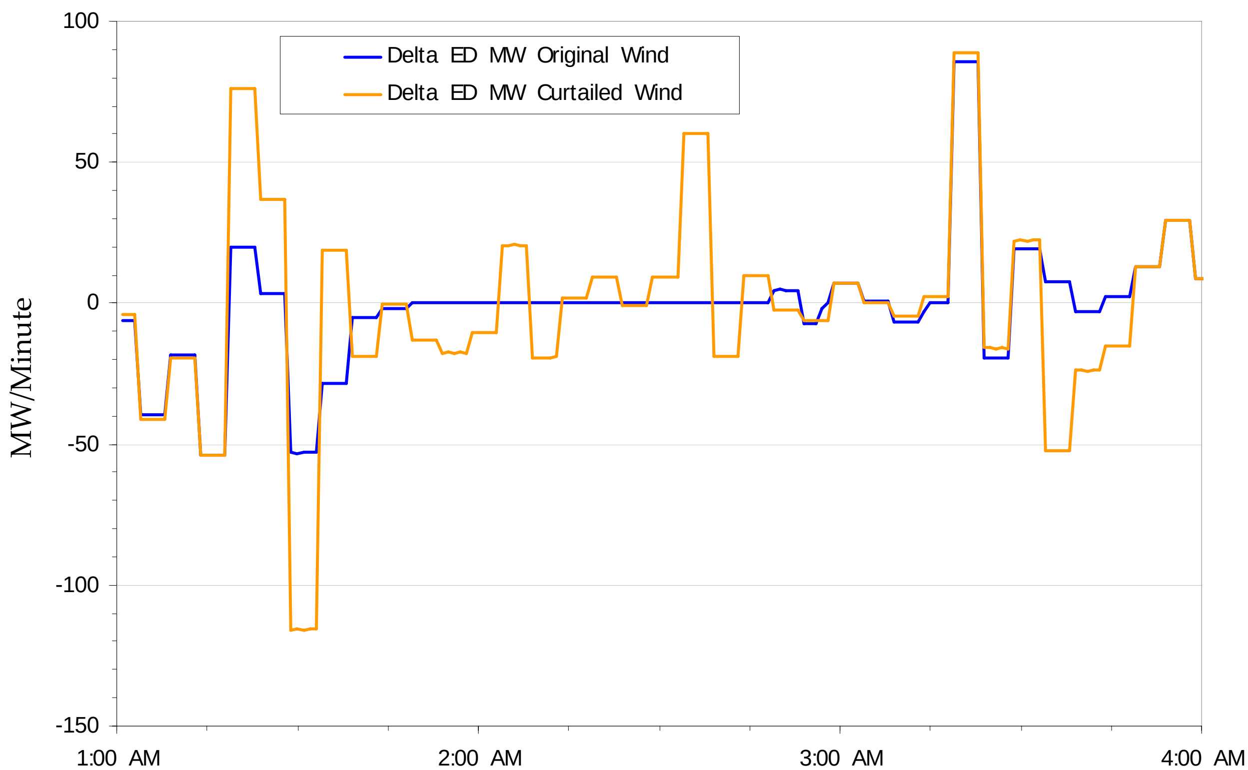


**Figure 141. Impact of Temporary Curtailment of Wind Generation on Economic Dispatch and Load–Following Duty During May QSS Study Period.**

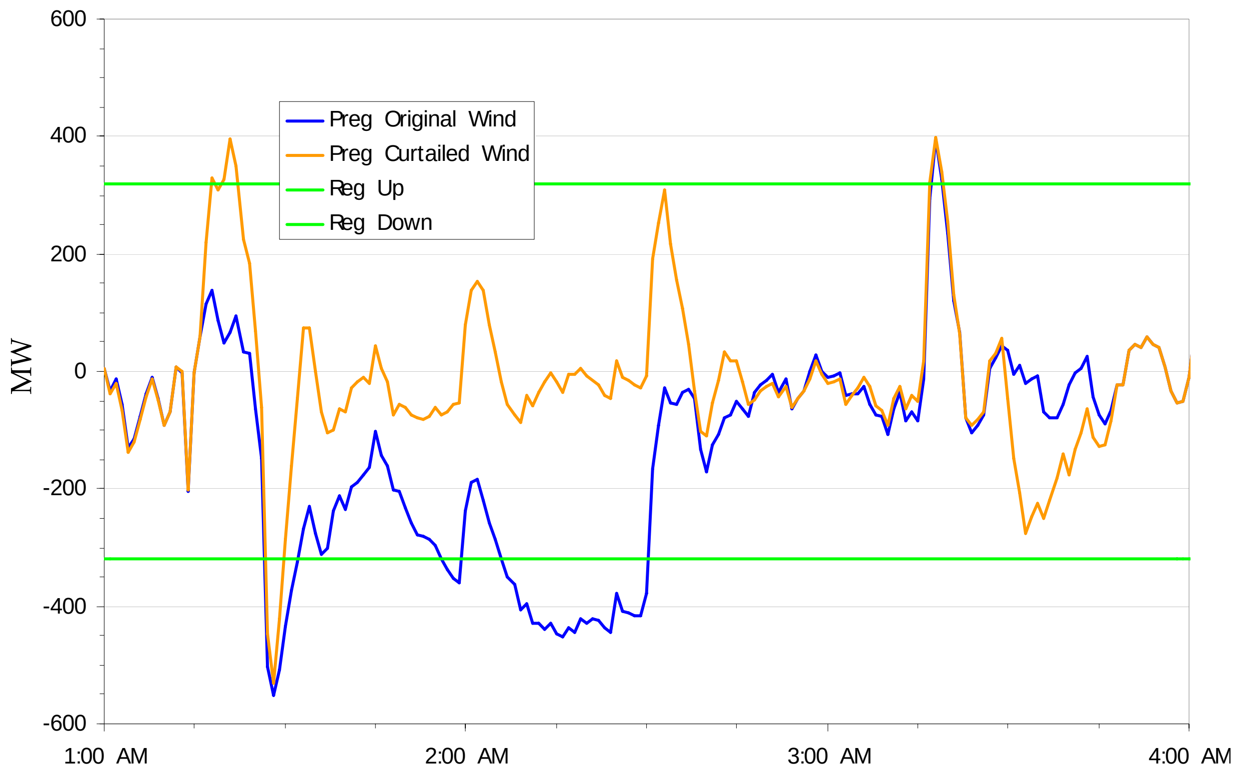


**Figure 142. Impact of Temporary Curtailment of Wind Generation on Regulation Duty During May QSS Study Period.**

### *Remove Large Steps from Load Profile*

The May simulation results have all shown that large steps in load have a more significant impact on regulation than wind variability. As noted previously, these large load steps are probably due to switching pumped storage hydro facility pumps. While schedulable, such pump switching events still have a significant impact on system performance.

Nonetheless, a sensitivity case was developed to evaluate load and wind variability without the disruption of large load switching events. This was accomplished by removing all load steps with an absolute value greater than 200 MW from the original load profile, as shown in Figure 143. In this figure, the original load profile is represented by the blue line and the modified load profile is represented by the yellow line.

As context, selected May night load profiles from the California ISO provided data are shown in Figure 144. The load profile for this May QSS study period is represented by the yellow line. While this profile shares the general shape of all of the other plotted profiles, it is the only one with significant step down in load between midnight and 3 am. All other profiles show positive load steps in this time frame, which is consistent with the practice of switching in pumped storage hydro facilities at light load. Therefore, the May QSS study period is one of the most severe tests of the need to maintain down maneuverability under light load conditions.

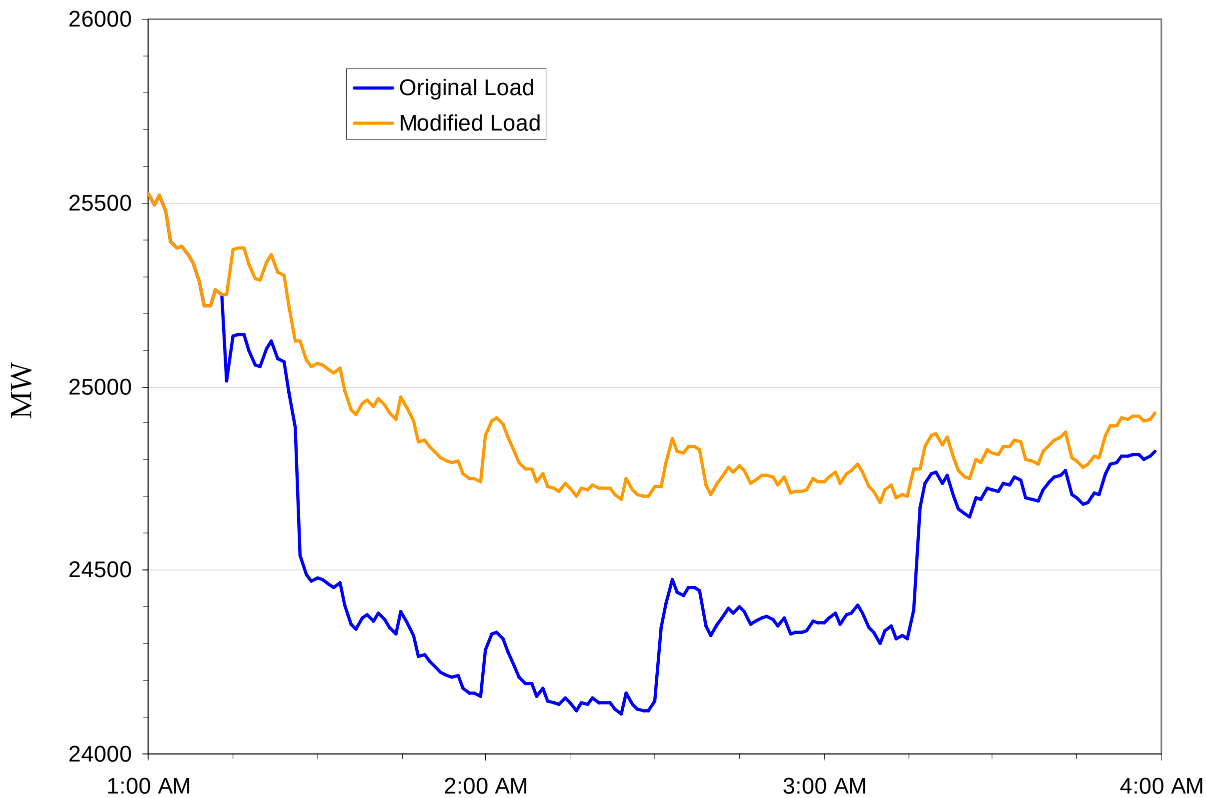


**Figure 143. Modified Load Profile Without Large Switching Events.**

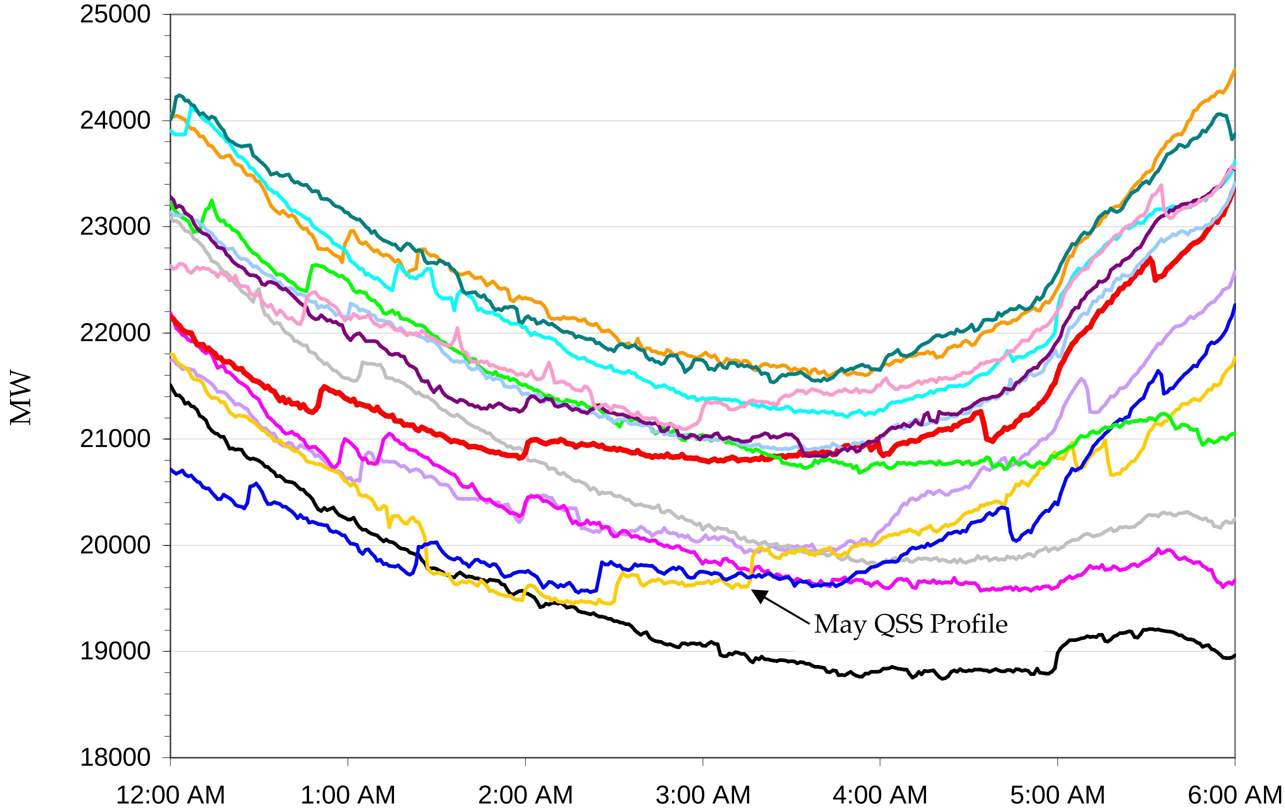


**Figure 144. Selected California ISO 1-Minute Load Data from May 2002, 2003, and 2004.**

The QSS maneuverability variables (defined in Section 5.2.1) with the modified load profile are shown in Figure 145. The green line represents Pmxtot, which is a constant 5,500 MW during the QSS simulation. Similarly, the lavender line represents Pmntot, which is constant at about 1,100 MW. The up ramp rate capability (RUPtot) of the ED units is represented by the yellow line, and the down ramp rate capability (RDNtot) is represented by the pink line. Similarly, the remaining up range available on the ED units (PUPtot) is represented by the red line, and the remaining down range (PDNtot) is represented by the turquoise line. The black line shows the total actual output of the ED units (Sum ED MW). With the original load profile, the down maneuverability of the ED units was exhausted, as shown in Figure 134. With the modified load profile, the down maneuverability of the ED units was not exhausted.

The QSS performance results (also defined in Section 5.2.1) with the modified load profile are shown in Figure 146. The blue trace shows the minute-to-minute change in net load (Delta L-W-S). The green trace shows the amount of power required on a 1-minute basis to balance generation and load (Preg). The yellow lines (Reg Up, Reg Down) show the minimum regulation procured during this study period. These results indicate that accommodating the variability of both the load and significant wind generation is within the capability of the system.

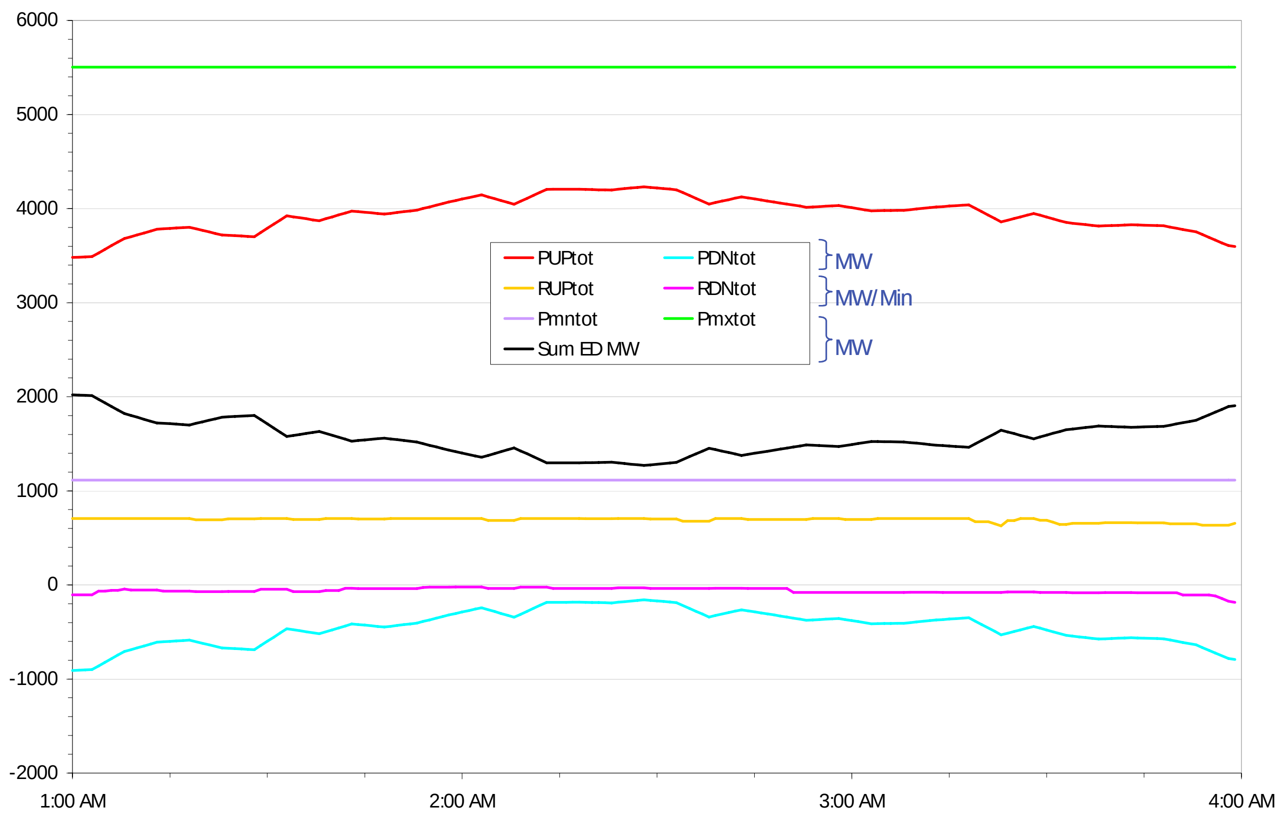


**Figure 145. Maneuverability Variables for a May Night with the Modified Load Profile.**

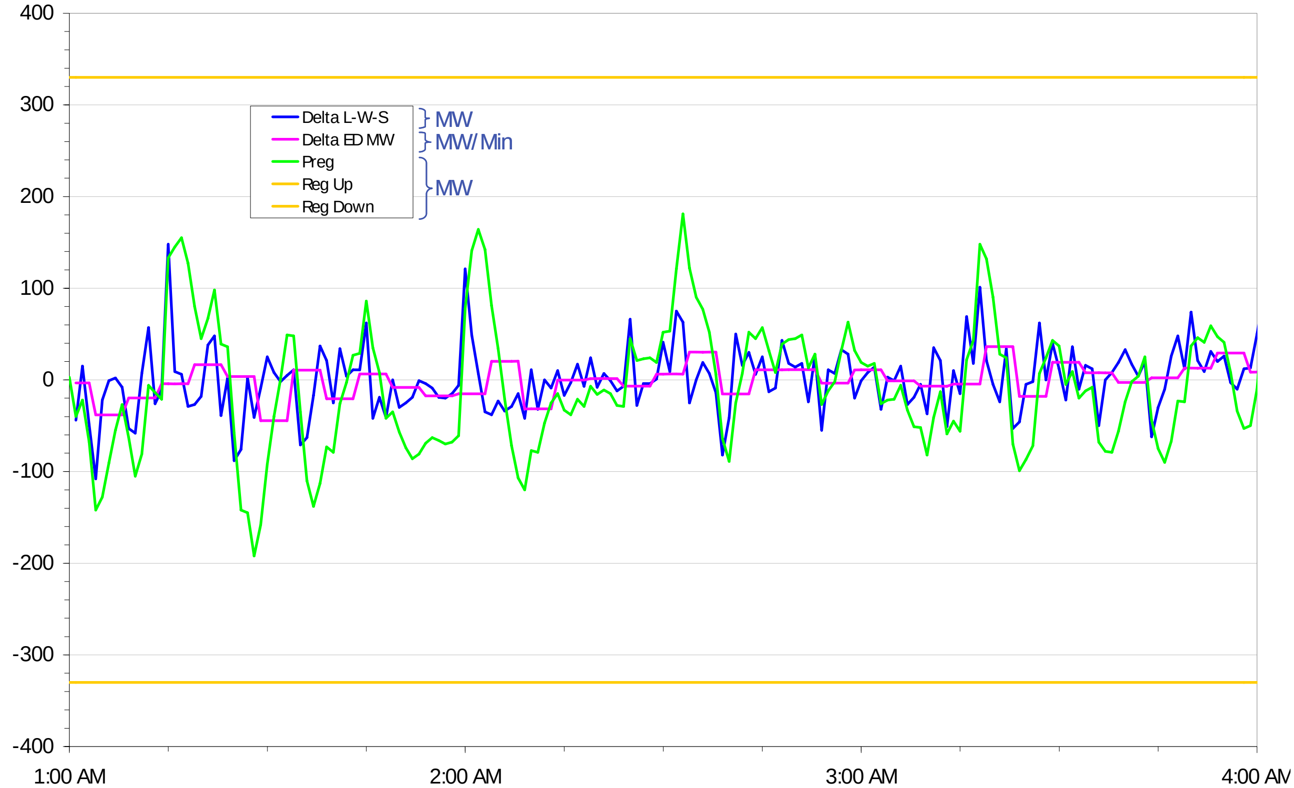


**Figure 146. Performance Variables for a May Night with the Modified Load Profile.**

### *5.2.3. June Evening Load Decrease*

The June evening study period was evaluated under the 2010X renewable scenario, which includes about 12,500 MW of wind generation capacity at 142 sites and 2,600 MW of solar generation capacity at 42 concentrating solar plants and 128 PV sites. The load was derived from the 2004 data.

As shown in Table 32, this study period included a decrease in load (-2,700 MW) combined with a significant increase in wind generation (4,400 MW) and a decrease in solar generation (-900 MW). This results in a net load decrease of about 6,200 MW. As context, note that the three years of hourly data showed this case has the single largest 1-hour increase in wind generation of about 3,500 MW. The data also showed that the maximum 3-hour increase in wind generation was about 4,900 MW, and a 3-hour wind increase greater than 4,400 MW occurred 13 times.

The total load profile for the June evening study period is shown in Figure 147. This evening load drop is not monotonic, and includes a steep decline at about 4:15 pm. The total wind generation profile for this study period is shown in Figure 148. There is a rapid and sustained wind increase during the first hour, which is largely monotonic. The total solar generation profile is shown in Figure 149. The decline in solar output tends to coincide with the load decrease. These three figures provide an overview of the input to the QSS simulation.

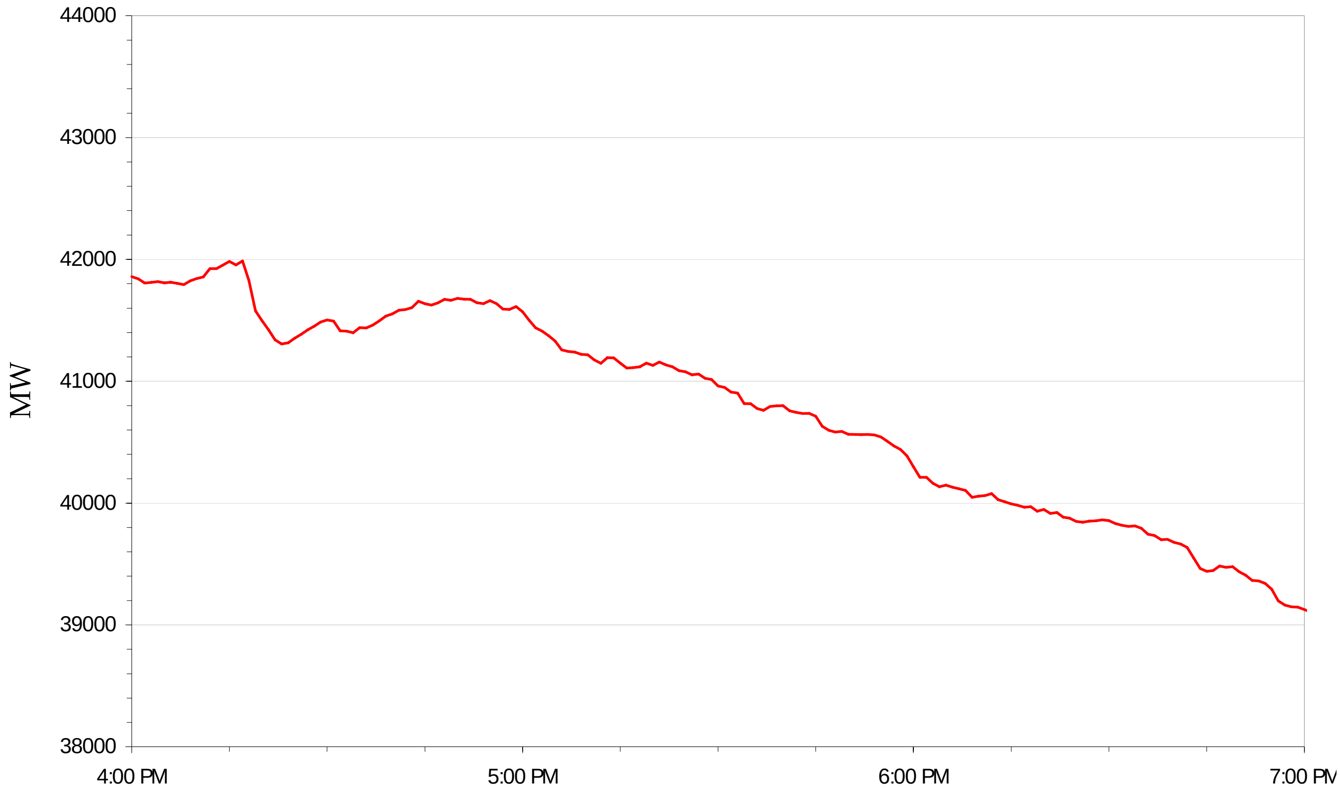


**Figure 147. Total California Load During the June Evening QSS Study Period.**

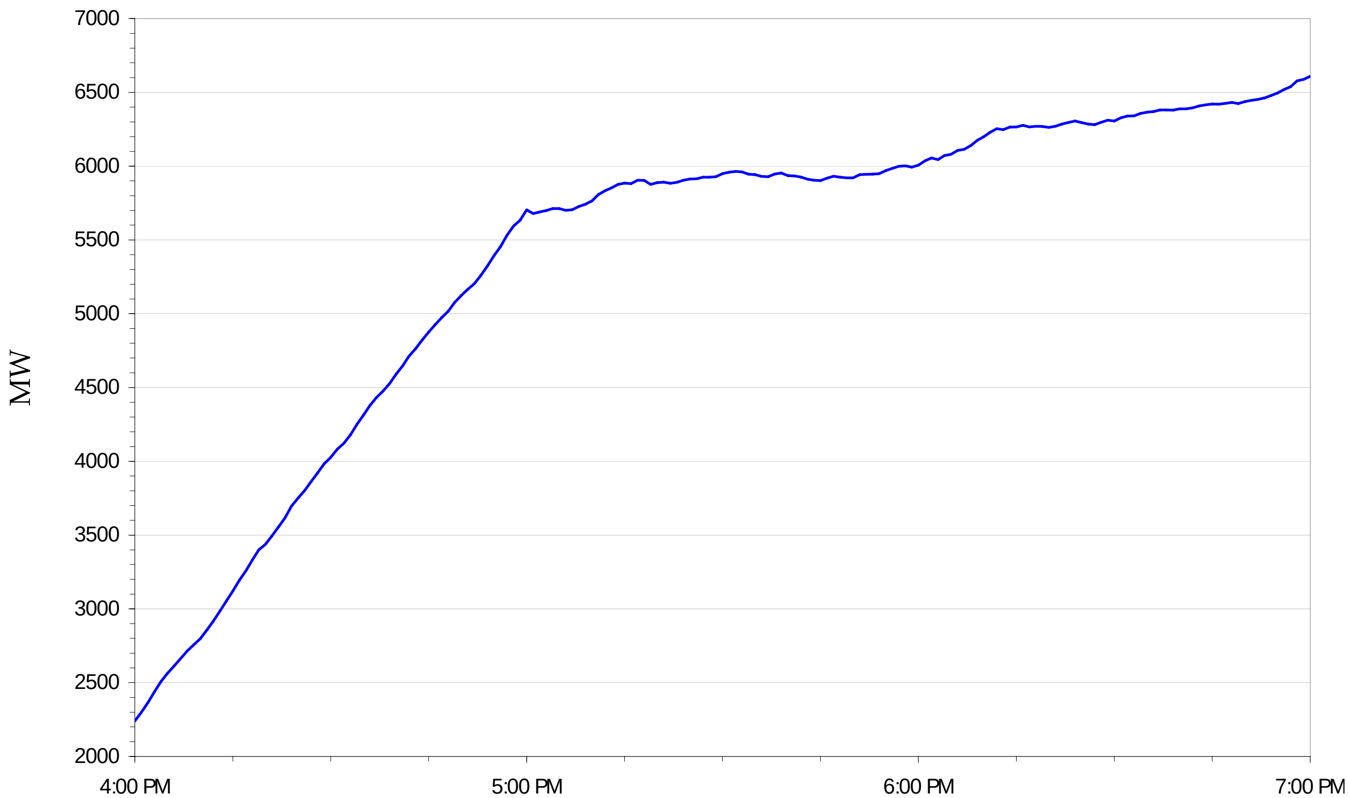


**Figure 148. Total California Wind Generation During the June Evening QSS Study Period.**

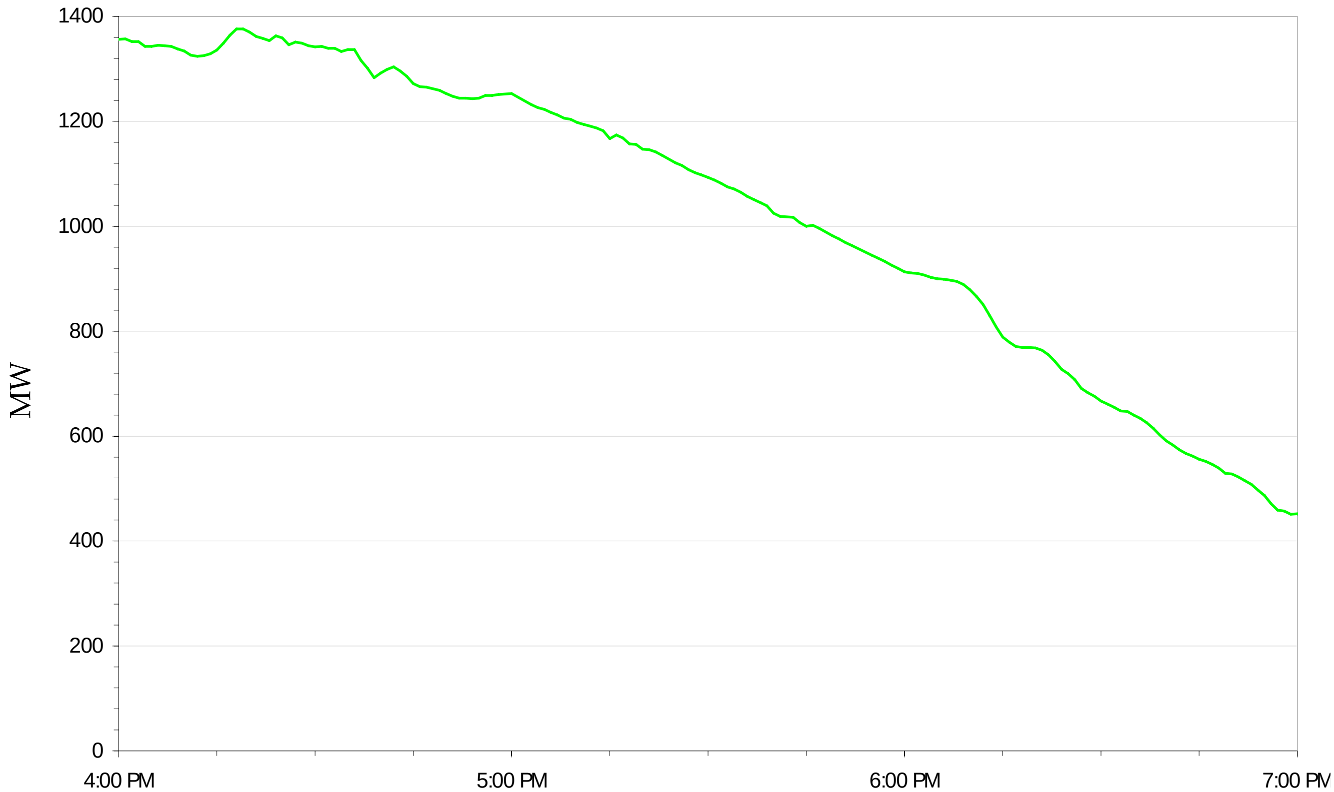


**Figure 149. Total California Solar Generation During the June Evening QSS Study Period.**

The QSS maneuverability variables (defined in Section 5.2.1) for the June study period are shown in Figure 150. The green line represents Pmxtot, which is a constant 10,800 MW until about 6:30 pm when a large amount of pumped storage hydro, which had been generating power, was switched off. The lavender line represents Pmntot, which is constant at about 2,800 MW throughout the simulation. The up ramp rate capability (RUPtot) of the ED units is represented by the yellow line, and the down ramp rate capability (RDNtot) is represented by the pink line. Similarly, the remaining up range available on the ED units (PUPtot) is represented by the red line, and the remaining down range (PDNtot) is represented by the turquoise line. The black line shows the total actual output of the ED units (Sum ED MW). The down maneuverability of the ED units is almost completely exhausted by the end of the simulation.

The QSS performance results (also defined in Section 5.2.1) for the June study period are shown in Figure 151. The blue trace shows the minute-to-minute change in net load (Delta L-W-S). The green trace shows the amount of power required on a 1-minute basis to balance generation and load (Preg). The yellow lines (Reg Up, Reg Down) show the minimum regulation procured during this study period. These results again indicate that the load step at about 4:15 pm is largely responsible for the excursion beyond the procured regulation thresholds . However, the sustained wind increase over the first hour is largely responsible for the offset indicated by the heavy yellow line. During this period the ED units are not providing sufficient load following, so that requirement is shifted to the AGC proxy unit (Preg).

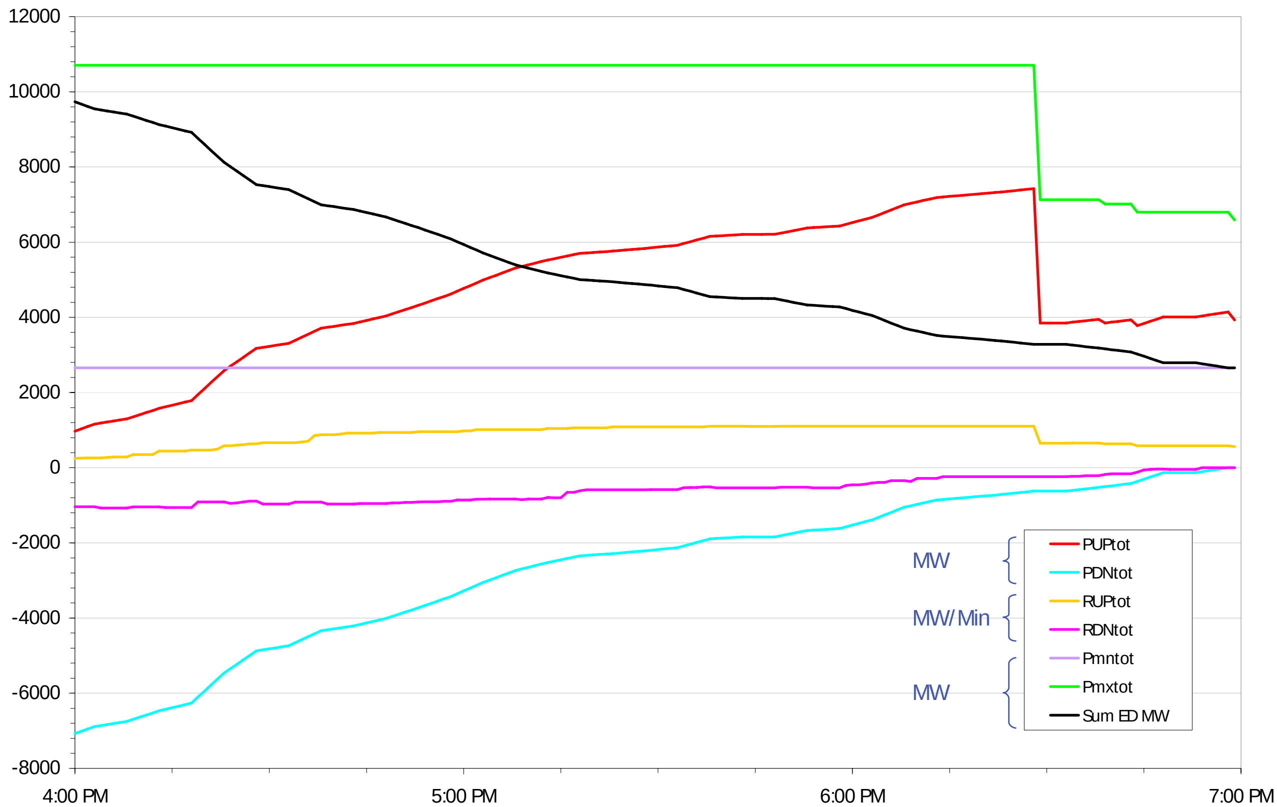


**Figure 150. Maneuverability Variables During the June Evening QSS Study Period.**

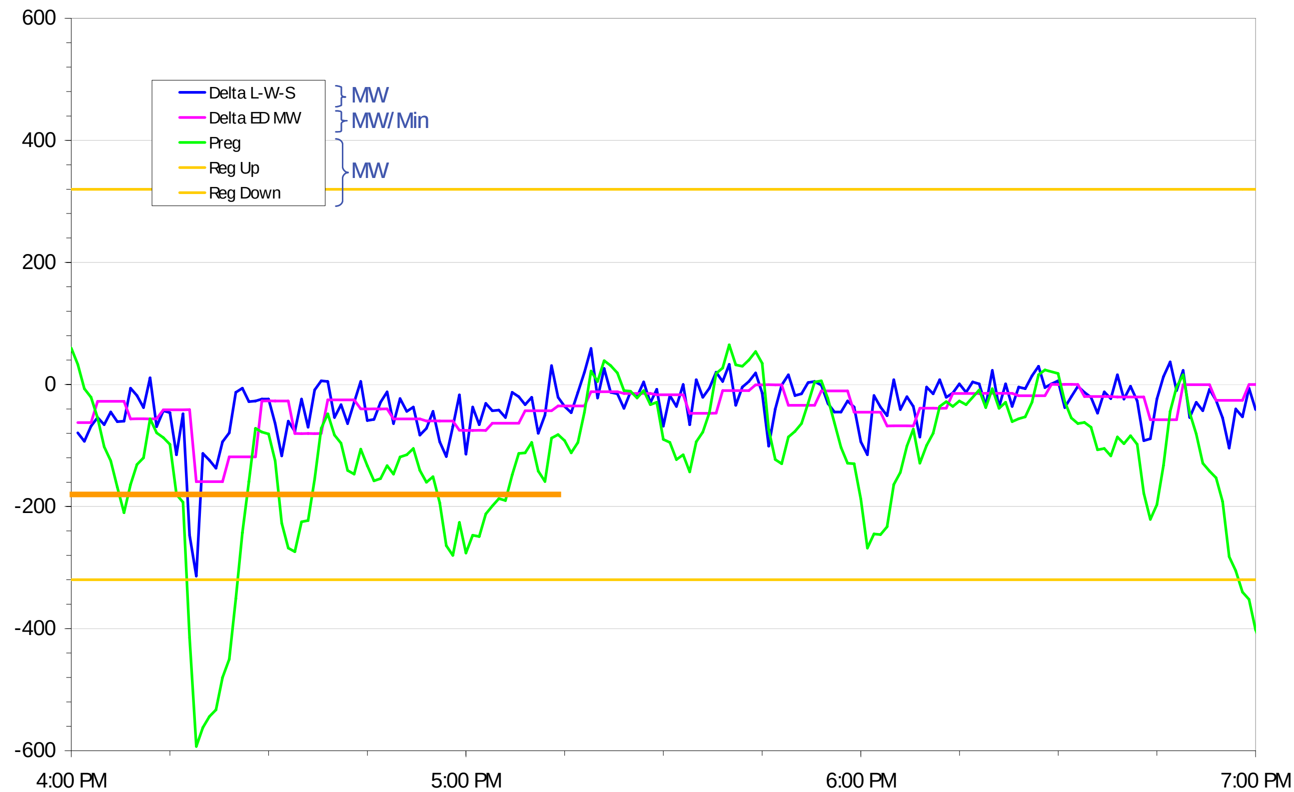


**Figure 151. Performance Variables During the June Evening QSS Study Period.**

### *Incorporate Hourly Wind Forecast*

As noted in the description of the QSS method (Section 5.1), the simplified economic dispatch model includes an hour-ahead schedule function. This function nominally includes a perfect forecast for both load and solar generation, and a persistence-based forecast for wind generation. A persistence forecast assumes that the wind generation in the next hour will be the same as it is in the current hour.

The June QSS results described above showed that load following requirements were shifted to regulation during periods with a sustained increase in wind power. Modifying the economic dispatch model to include a short-term wind forecast is one potential mitigation method to prevent this shift.

Cross plots of the QSS simulation results with and without an hour-ahead wind forecast are shown in Figure 152 and Figure 153.

Figure 152 shows the impact of incorporating an hour-ahead wind forecast on the duty imposed on the proxy AGC unit. The blue line represents the original economic dispatch model with a persistence-based wind forecast, and the yellow line represents the improved economic dispatch model. The green lines represent the minimum up and down regulation procured during this study period. Originally, the proxy AGC unit output was offset by an average of about -180 MW, as indicated by the heavy blue line. With an hour-ahead forecast included, the offset is reduced to about -60 MW, as indicated by the heavy yellow line. This shows that the ED units are better able to follow load with the improved wind forecast incorporated into the dispatch function.

Figure 153 shows the impact of an improved wind forecast on the economic dispatch and load following requirements. The blue line represents the original economic dispatch model with a persistence-based wind forecast, and the yellow line represents the improved economic dispatch model. With the original economic dispatch model, the ED units were unable to keep up with the rapid increase in wind generation. With the incorporation of an improved wind forecast, the ED units do provide sufficient load following during the key time frame – the first 15 minutes of the study period.

Thus, incorporating a short-term forecast into the economic dispatch model improves system performance. This study scenario used a perfect forecast for illustration. A state-of-the-art short-term forecast would still provide improved performance overall. However, there would be times when the short-term forecast was wrong. During these times, incorporation of the forecast into the economic dispatch could have an adverse impact on system performance.

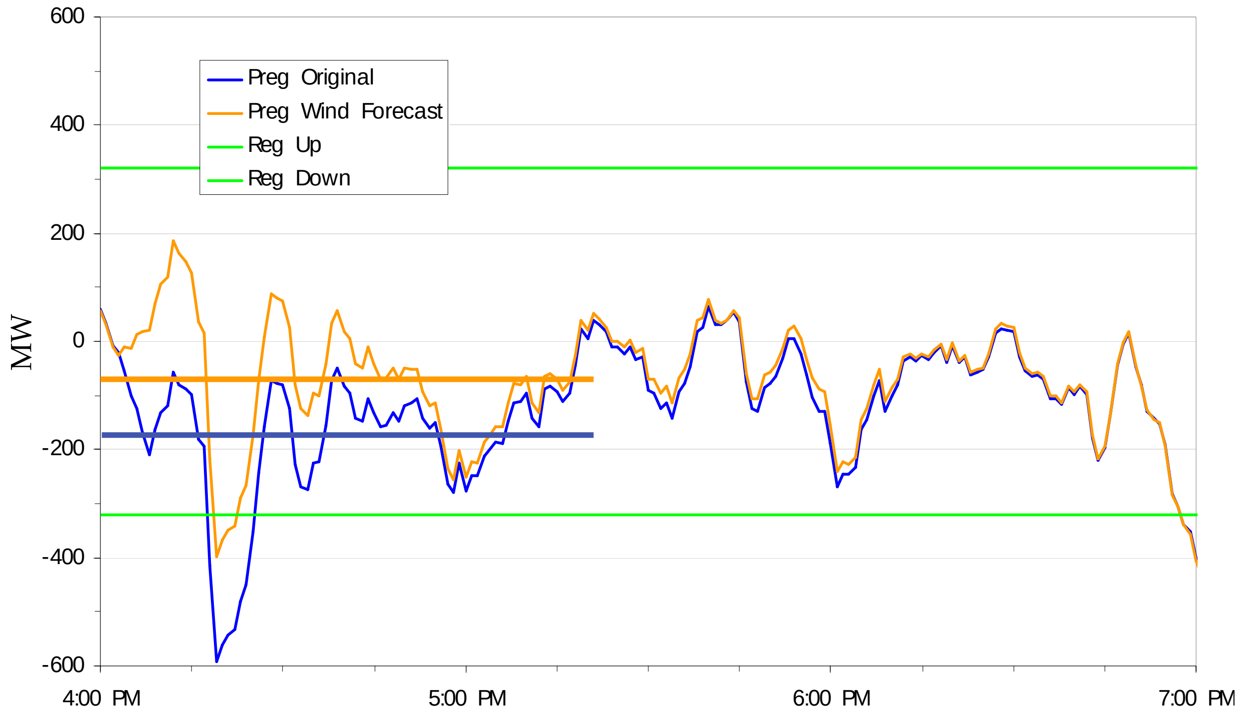


**Figure 152. Impact of Including Hourly Wind Forecast on Regulation Duty During the June Evening QSS Study Period.**

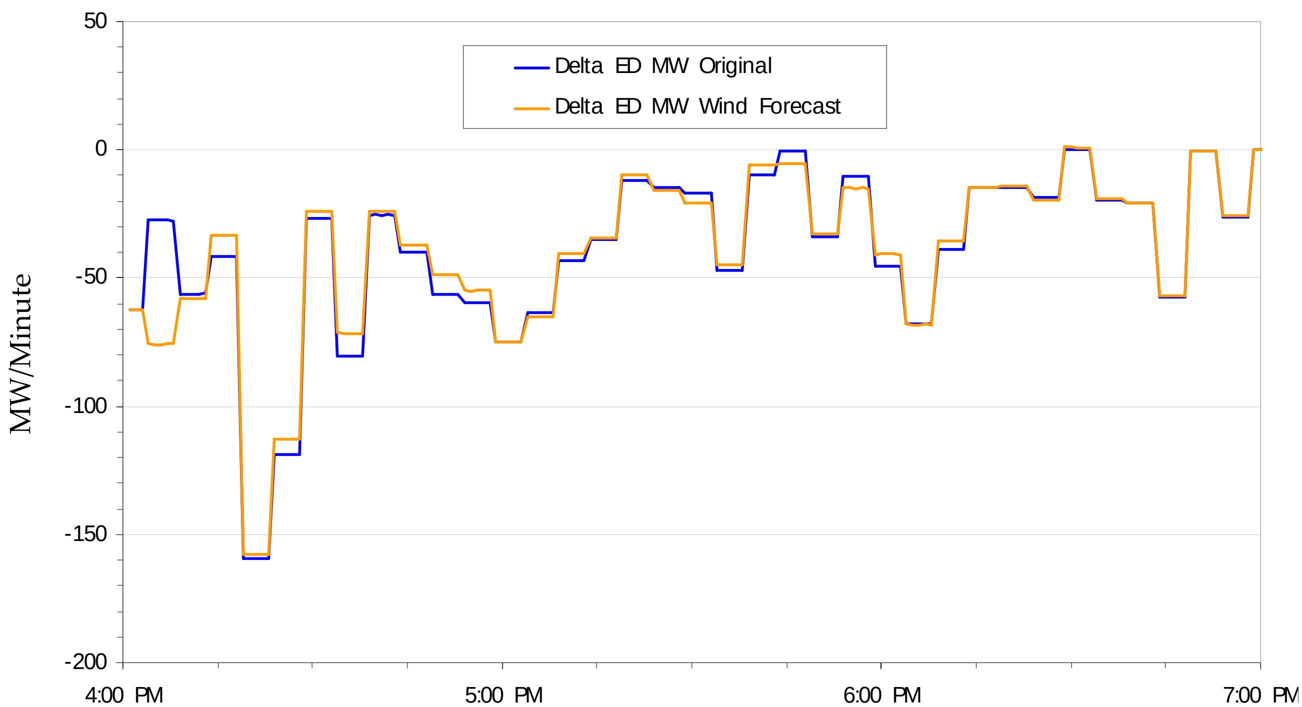


**Figure 153. Impact of Including Hourly Wind Forecast on Economic Dispatch and Load Following During the June Evening QSS Study Period.**

### *Temporary Wind Ramp Rate Limit*

The previous section explored one mitigation method for responding to rapid increases in wind generation – incorporating an hour-ahead wind forecast into the economic dispatch model. Another mitigation method, a temporary ramp rate limit on increasing wind generation, is examined in this section. The original June wind profile (blue line) and the ramp rate limited wind profile (yellow line) are shown in Figure 154. For this illustration, a cap on wind generation is applied at approximately 4:15 pm. This was triggered by the AGC when the regulation requirement approached the procured regulation threshold. Total wind production was capped for the next 15 minutes. The cap was then removed and wind farm output was allowed to increase at no more than 1%/minute for the duration of the simulation. Hence, the total wind output with the cap and ramp rate limit never returns to the original level. This temporary cap and ramp rate limit was implemented at all wind farms. The wind energy lost during the curtailment was about 550 MWh out of about 16,300 MWh, or 3.5%, for this 3-hour period.

Cross plots of all three sets of QSS results for the June study period are shown in Figure 155 and Figure 156. In both figures, the dark blue line represents the original case with no wind generation cap and ramp rate limit and with a persistence-based wind forecast. The yellow line represents the first sensitivity case with no wind generation cap and ramp rate limit but with an hour-ahead wind forecast incorporated in the economic dispatch. The light blue line represents the second sensitivity case with the wind generation cap and ramp rate limit and with a persistence-based wind forecast.

Figure 155 shows the output of the proxy AGC unit for the three scenarios. Note that the short term depletion of regulation capability is greatly reduced by either incorporating a wind forecast into the economic dispatch model or limiting the wind generation during periods of significant increase.

Figure 156 shows the ED unit signal for the three scenarios. Again, both mitigation methods allow the ED units to provide sufficient load following during the key time frame – the first 15 minutes of the study period.

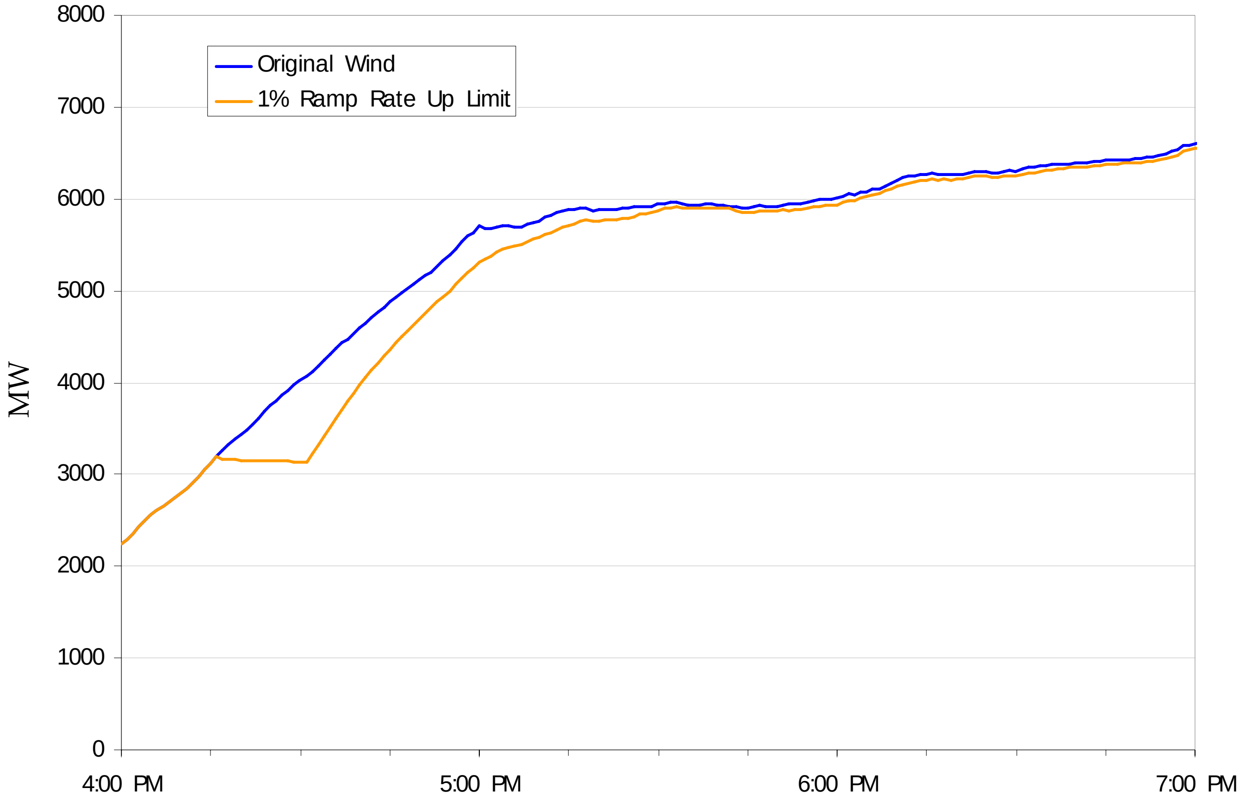


**Figure 154. Temporary Cap with Ramp–Up Rate Limit on Wind Generation.**


**Figure 155. Comparison of Regulation During the June Evening QSS Study Period.**

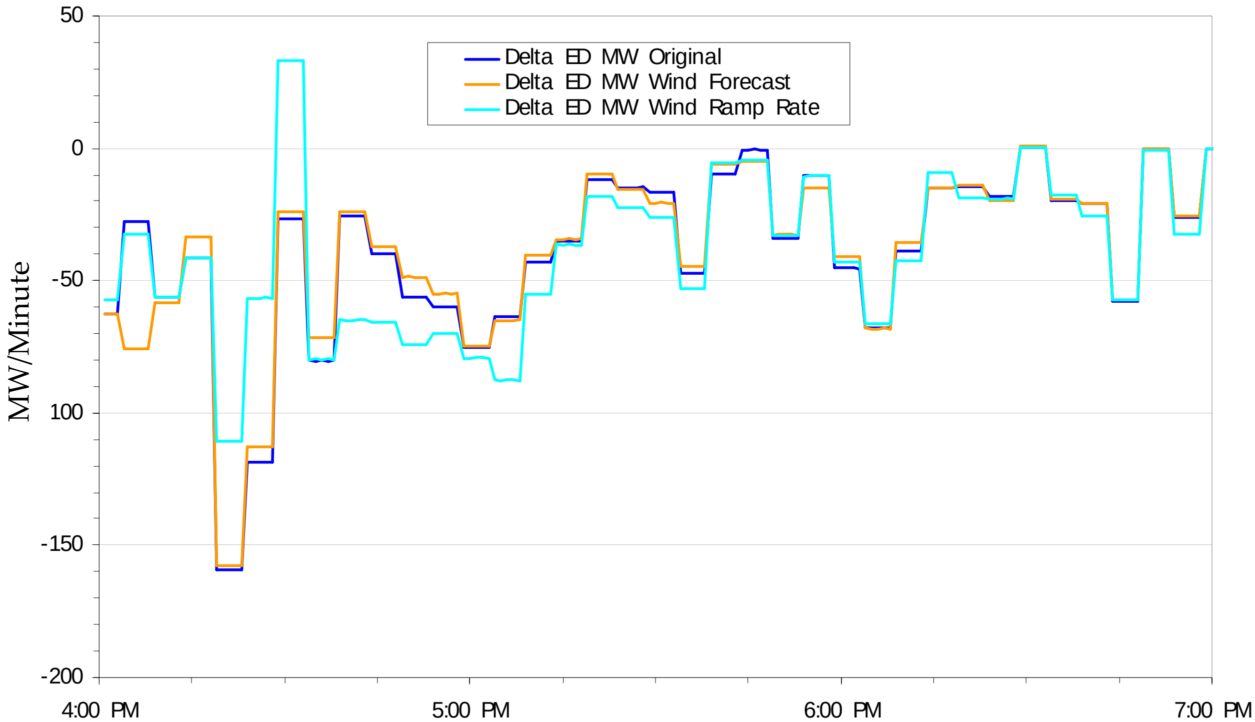


**Figure 156. Comparison of Economic Dispatch and Load–Following During the June Evening QSS Study Period.**

## 5.3. Summary of Results

A summary of the QSS analysis in each of the study periods (e.g., July morning load rise, May night light load, June evening load decrease) is provided in this section.

The July morning load rise simulations illustrated:

- Load following increases due to a net decrease in renewable generation
- Most of the load following is performed by combined-cycle plants, followed by hydroelectric units
- The regulation duty is due primarily to load variation, but is offset up by the decrease in wind power
- In general, an economically rational unit commitment and dispatch provides adequate load following capability

The May night light load simulations illustrated:

- Large steps in load have more significant impact on regulation than wind variability
- Insufficient down capability (both range and ramp rate) shifts load following duty to regulation, which may then become exhausted
- Variability of wind increases the ED unit duty, both in terms of MW/minute and the frequency of sign changes

- The importance of using available maneuverability, and avoiding non-technical constraints
- Change in commitment or curtailment of wind effectively mitigates loss of maneuverability

The June evening load decrease simulations illustrated:

- Regulation picks up sustained changes in wind power
- This increases the likelihood that regulation will be exhausted, and less able to respond to rapid changes in load
- Incorporating a short-term wind forecast into the schedule can improve load following and reduce the shift to regulation duty
- Short-term curtailment of wind rise (with ramp-rate limitation) can also achieve that goal. Some wind energy production is lost to achieve this benefit.

# 6.0 Operational Implications and Mitigation Methods

The preceding sections presented the impact of intermittent renewables on the California system from different perspectives: statistical expectations of variation and uncertainty (Section 3.0), overall day-to-day operation and economic behavior (Section 4.0), and selected illustrations of faster, intra-hour behavior (Section 5.0). In each section, results and observations particular to that analytical viewpoint were presented.

In this section, wind variability and uncertainty are further examined within the context of the relationship between these analytical perspectives. This provides additional insight into the overall operational implications of intermittent renewables and potential means of mitigating adverse impacts.

Throughout this report, the time frames for variability and the requirements for operational flexibility have been consistently defined as follows:

- 1-hour delta refers to the change from the previous hour. The ability of the operating area to accommodate hourly changes is called schedule flexibility.
- 5-minute delta refers to the change from the previous 5-minute period. Load following and economic dispatch functions operate in this time frame.
- 1-minute delta refers to the change from the previous minute. Regulation functions operate in this time frame.

In practice, the boundaries between these time frames are not crisply defined, and the resources and practices that impact one will often impact another.

The following sections will validate the study approach against historical data, examine the system flexibility requirements from an operational perspective, and describe selected mitigation strategies.

## 6.1. Validation

In this section, the study approach and results are compared, and validated, against historical data and performance.

A typical day of operation, as recorded by the California ISO, is shown in Figure 157. This is 4-second resolution data. Therefore, it shows all of the time frames examined in this project. The total California ISO load is represented by the pink line, the total generation under California ISO control is represented by the light blue line, and the total scheduled interchange is represented by the brown line. The left y-axis scale applies to the load and generation, and the right y-axis scale applies to the interchange. The interchange schedule is largely block scheduled on the hour, with roughly 10-minute transitions. As expected, the in-state generation closely tracks the system load.

This validates a basic analytical premise of this project. Specifically, WECC-wide unit commitment and dispatch is properly captured with the one-hour resolution used in the production simulation analysis. This figure also shows that essentially all of the load-following is performed by in-state generation. The maneuvering capability evaluation (Section 4.0), was based on this assumption. Equally important, this was a basic boundary condition for the QSS analysis (Section 5.0): only a subset of available California generations units were used to examine load-following behavior.

Figure 158 shows a week of actual historical interchange. Note that the interchange follows one-hour modifications, and there is considerable day-to-day variation. The instantaneous range, from minimum to maximum, of these seven days is shown in Figure 159. The maximum variation in interchange was about 3,000 MW, and consistently varies from 500 MW to 2,000 MW during light load periods. This validates the economic variability in California's power exchange with neighboring systems as shown in the production simulation analysis.

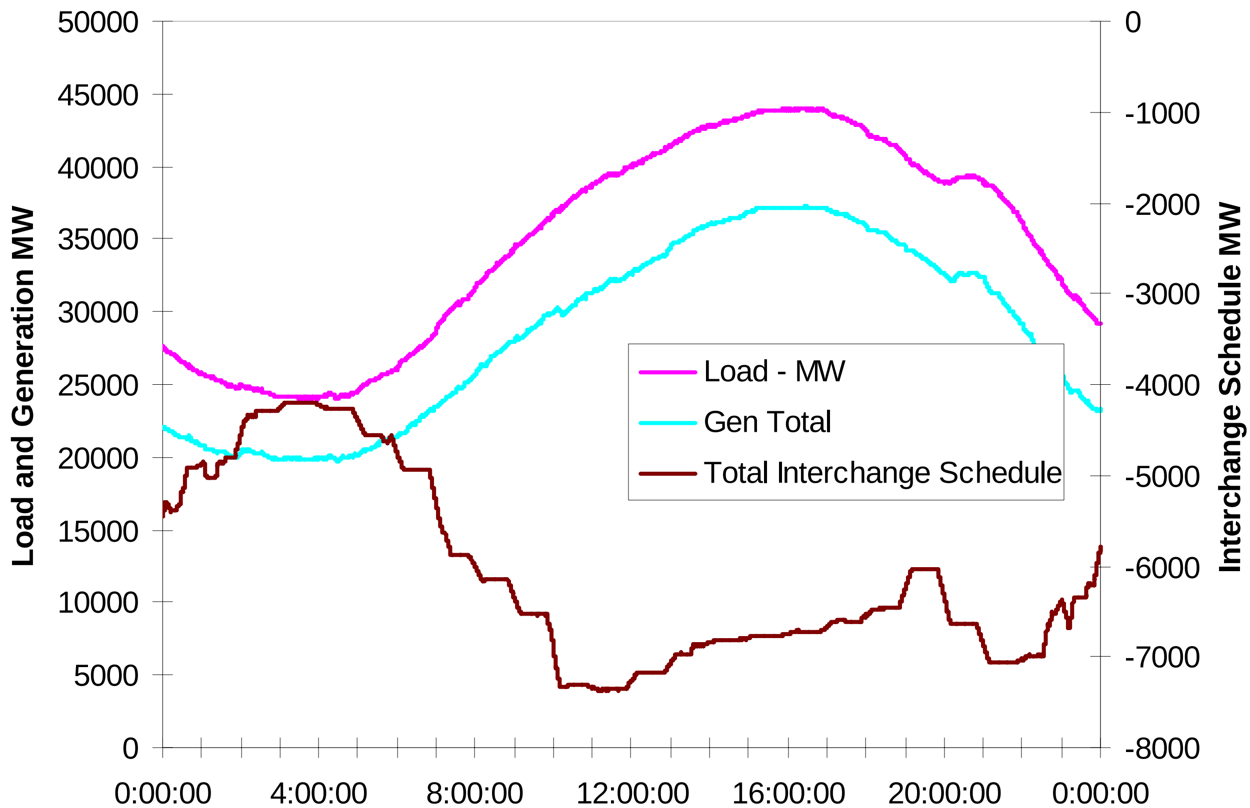


**Figure 157. Schedule and Load Following for a Sample Day of California Operation.**

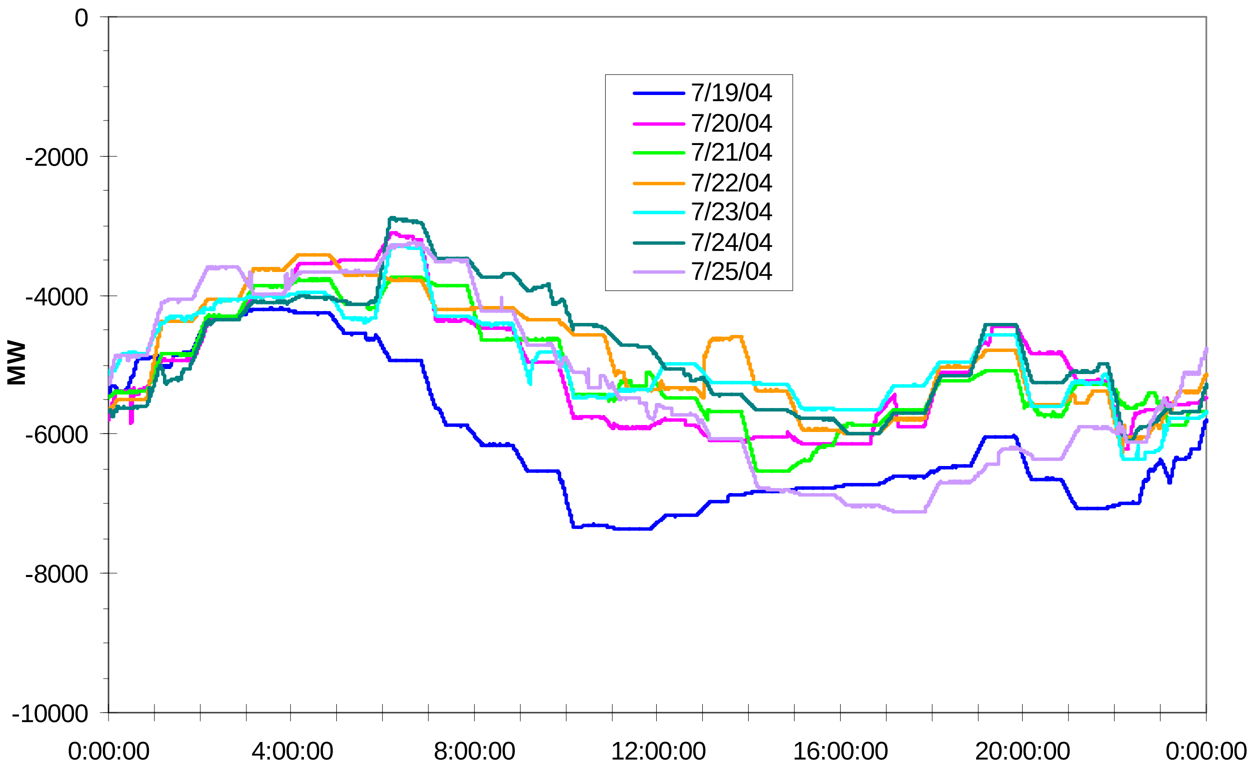


**Figure 158. Historical Interchange for a Sample July Week.**

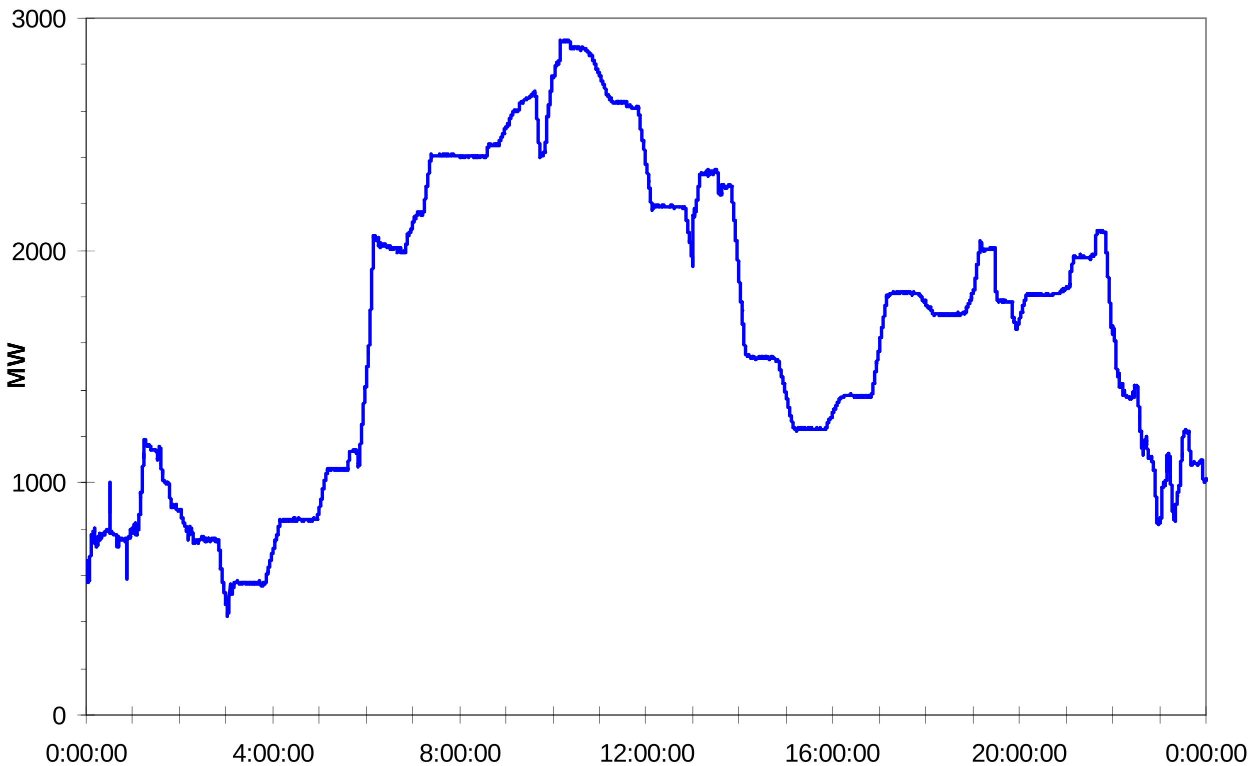


**Figure 159. Instantaneous Range of Interchange for Sample July Week.**

A closer inspection of the interchange shows expected performance in the regulation time frame. Figure 160 shows the scheduled (brown line) and actual (orange line) interchange for a sample day. It also shows the ISO control area control error (ACE, dark blue line). The left y-axis scale applies to the interchange signals, the right y-axis scale applies to the ACE signal.

The total interchange schedule occurs in one-hour blocks with transitions on the hour. Deviations from schedule, i.e., the difference between scheduled and actual interchange, mirrors the ACE signal. ACE generally varies in the range of ±200 MW, which is consistent with the California ISO's procurement of regulation services. Note that the largest ACE excursions correspond to the hourly schedule changes. Thus, the schedule changes may be causing avoidable ACE violations. The 5-minute economic dispatch works to correct these excursions, but the data suggests that more frequent interchange schedule changes (e.g., on the quarter or half hour) could also reduce the ACE excursions. Such schedule changes would also increase the flexibility available to address intermittent renewable variability. This issue is addressed further in the discussion of CPS2 (Section 6.3.4).

Note also that the continuous changes in load shown in Figure 157 are not observed in either the ACE or the schedule of Figure 161. This confirms that the majority of load following is performed by in-state generation, as was assumed for this study.

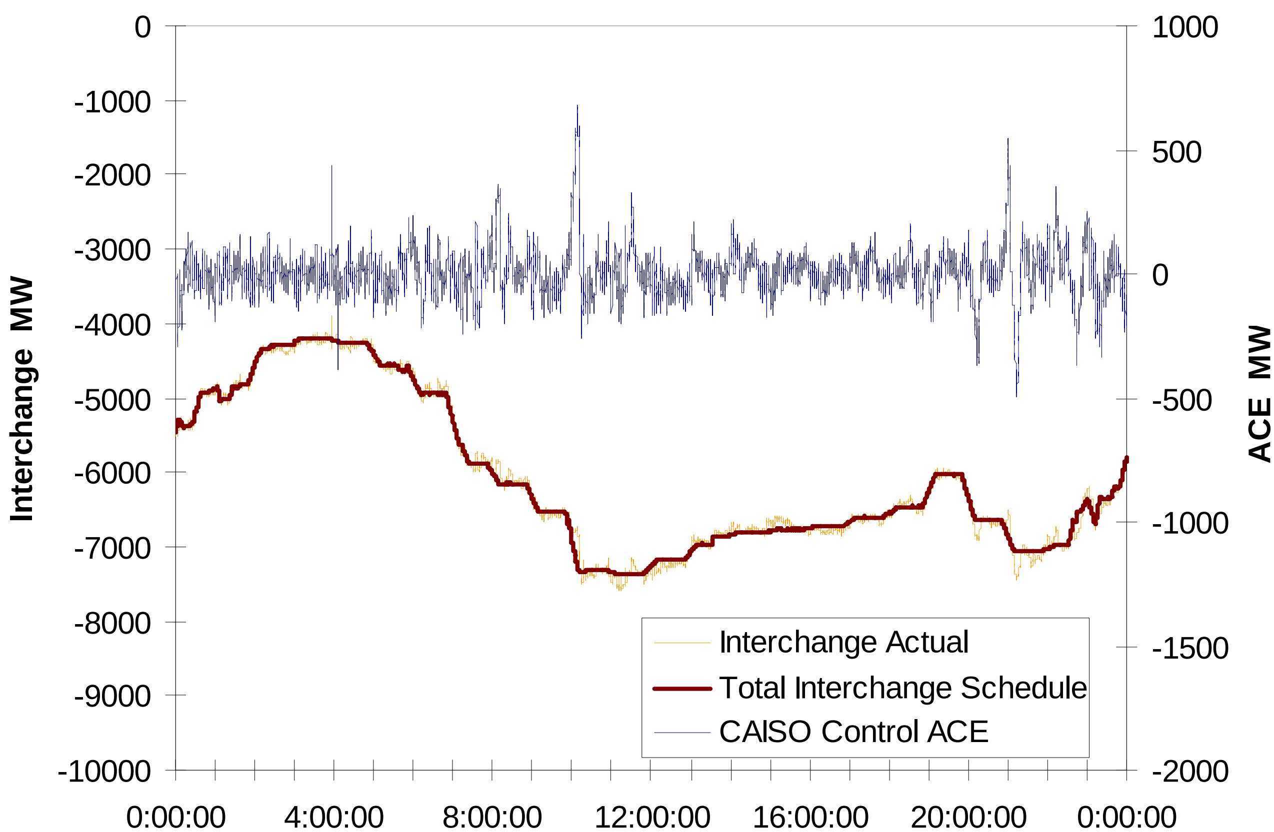


**Figure 160. Regulation and Interchange for a Sample Day of California Operation.**

The methods, assumptions, and results of the QSS analysis are validated by a comparison of Figure 161 and Figure 162. Figure 161 shows the actual California ISO ACE for three 3-hour periods: May 15, 2003 from 1am to 4am (blue line), June 24, 2004 from 4 pm to 7 pm (yellow line), and July 19, 2004 from 5am to 8am (green line). Figure 162 shows the output (Preg) of the proxy AGC unit from the QSS analysis of comparable time periods as projected for 2010. Again, the blue line represents the May study period, the yellow line represents the June study period, and the green line represents the July study period.

Note that the y-axis scale of the QSS results is larger than that of the historical data. The QSS results represent the 2010X scenario with significantly more load, as well as wind and solar generation, in comparison to the 2003 and 2004 historical data.

A second difference, one of sign convention, is also observed. The historical ACE is actual interchange minus scheduled interchange, ignoring the frequency term. Thus, a positive historical ACE indicates that generation in California ISO exceeds load, resulting in an increase in power export. In the QSS results, Preg is the power needed to balance generation and load. Thus, a positive Preg indicates that generation was less than load, resulting in output from the proxy AGC unit.

The key observation is that the overall character of the plots is similar. There is a large step in historical ACE at about 20 minutes into the June 24, 2004 data. There is a comparable, albeit larger, step in Preg from the June evening QSS analysis. There are similar large steps in the historical ACE data for the May time period at about 30 minutes, 90 minutes, and 135 minutes that are also reflected in the QSS results.

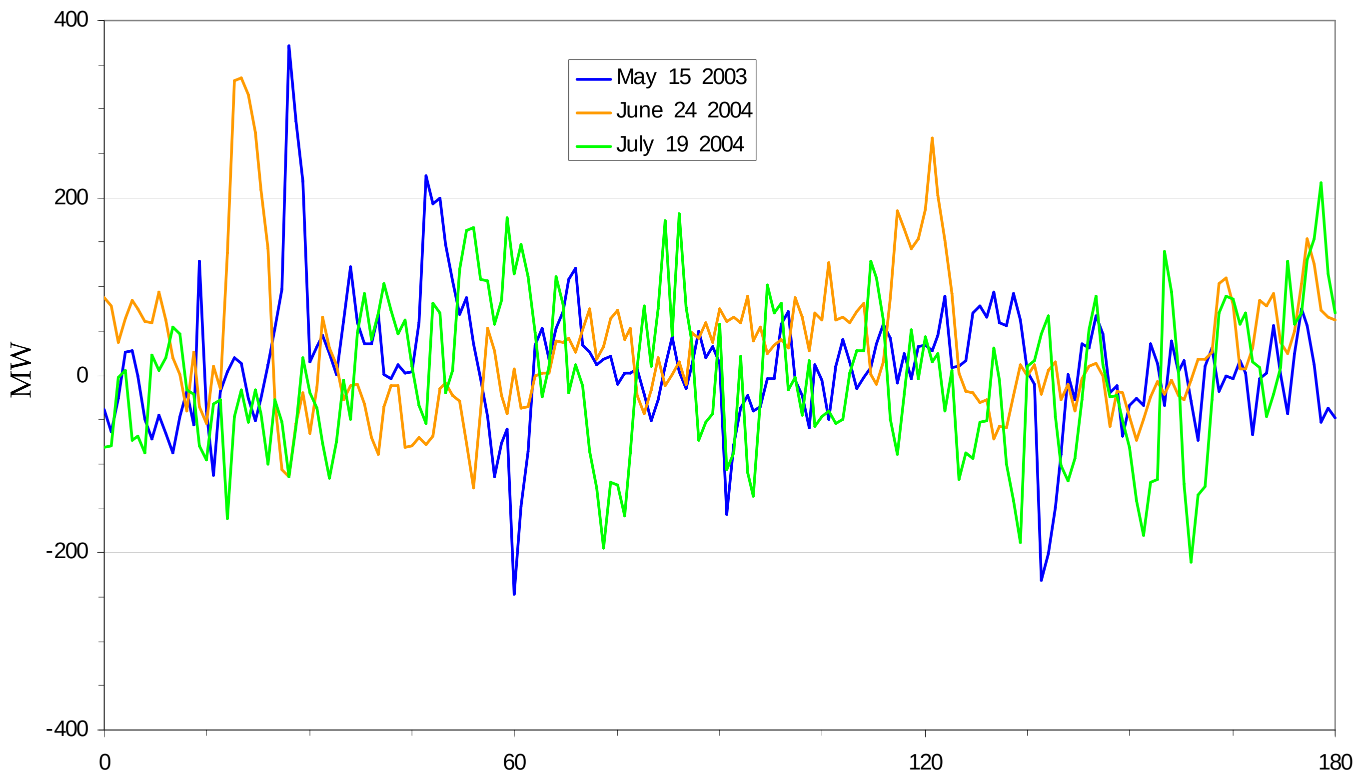


**Figure 161. Historical ACE Data.**

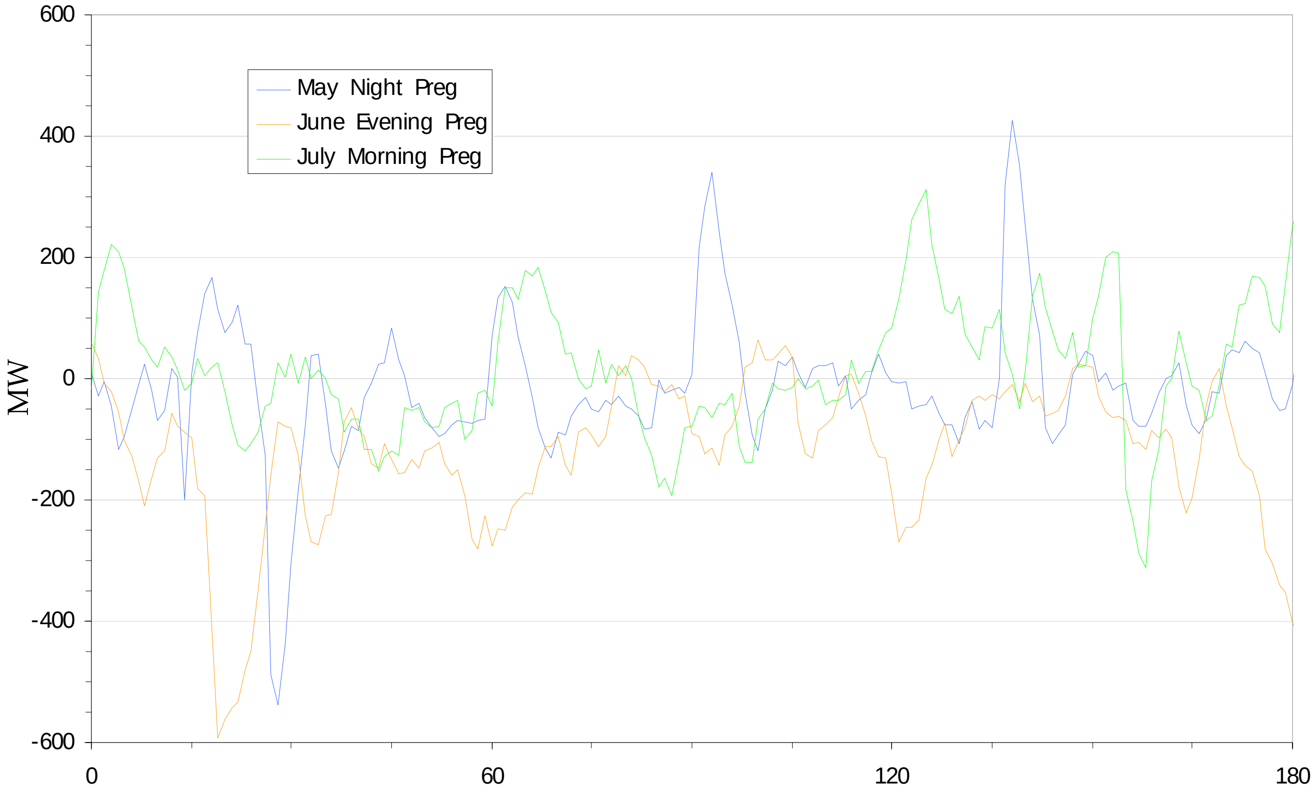


**Figure 162. Pseudo-ACE from QSS Simulations.**

Figure 163 shows a duration curve (blue line) of historical 2003 load data. It is sorted from highest load to lowest load, and the MW scale is on the left y-axis. The two other traces in this figure show the historical amount of up regulation (yellow line) and down regulation (green line) procured at each load level. The regulation data is not sorted, but is time-synchronized to the load data. The regulation MW scale is on the right y-axis.

The procured up regulation ranges from about 300 MW to 800 MW. In general, there is more up regulation procured at higher load levels than at lower load levels. This is consistent with the need to maintain load-serving capability, particularly during peak load times.

The procured down regulation is not as correlated with load level as the up regulation. It ranges from about –300 MW to –550 MW.

This data supports the use of a generic +320 MW of up regulation and –320 MW of down regulation in the QSS analysis. This is a conservative assumption for two reasons. First, the amount of regulation procured is often greater than 320 MW. Second, the QSS analysis is focused on the artificially accelerated 2010X scenario which includes significantly more load, as well as wind and solar generation, than is reflected in the 2003 data.

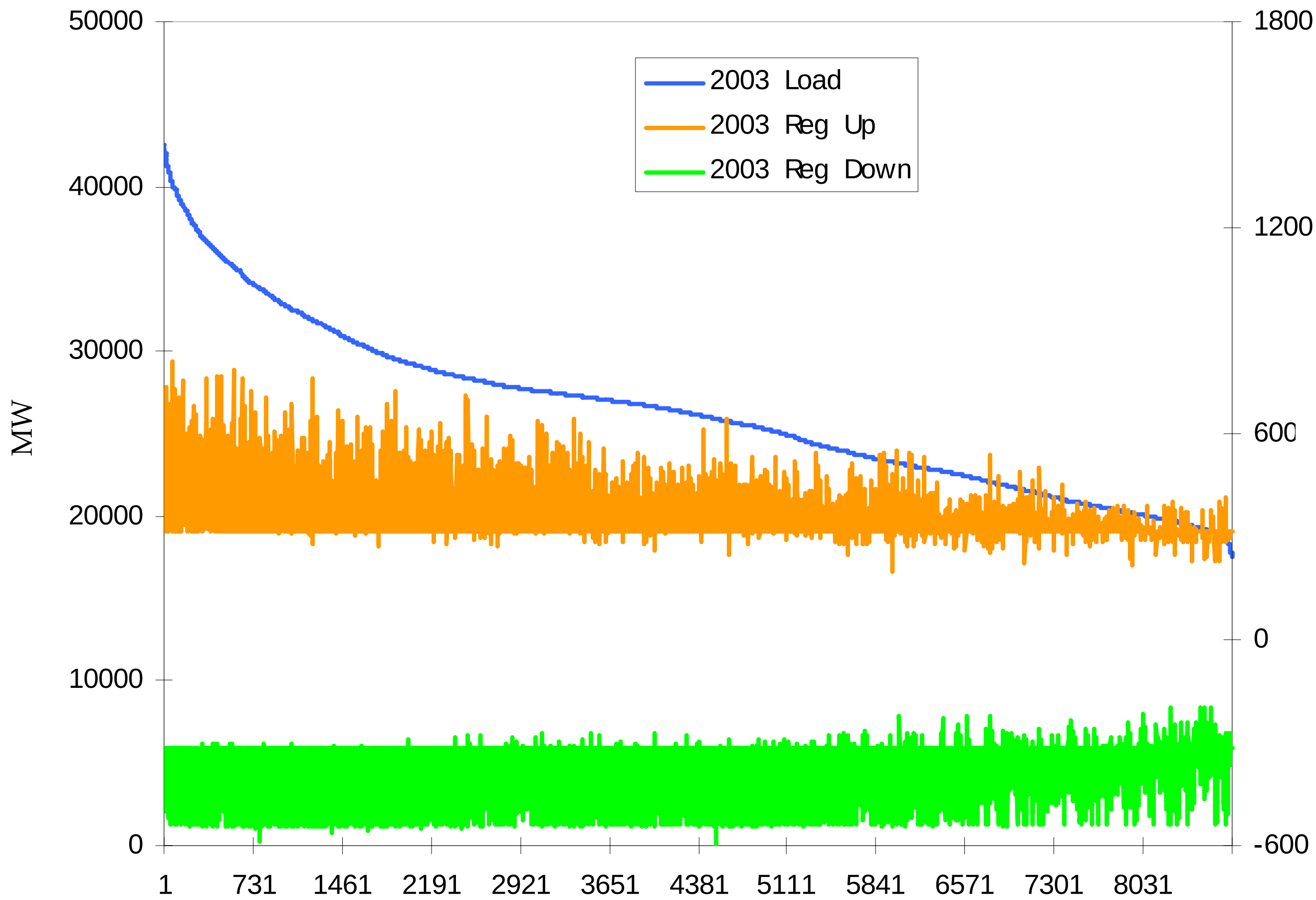


**Figure 163. Historical Load and Procured Regulation Data for 2003.**

## 6.2. Statistical Results and Operational Flexibility

In this section, selected statistical results from Section 3.0 are revisited in the context of the production simulation and QSS results. In general, the statistics provide insight into overall system variability as well as the impact of intermittent renewables. However, the statistic analysis did not address system operations and performance. With the results presented in Sections 4.0 and 5.0, it is possible to extract operational requirements from the statistical analysis. Specifically, the production simulation analysis identified the mix of resources available at any given time to meet the maneuverability/flexibility requirements. The QSS time simulations illustrated the relationship between the boundary conditions from the production simulation analysis and the minute-to-minute behavior of the system.

The statistical analysis examined the expected variability of load and intermittent renewables in different time frames. Throughout, the analysis assumed that this variability exhibited a normal distribution measurable with a standard deviation (σ). Examination of the distributions supported this approximation. In a normal population, three times the standard deviation covers the vast majority of events. That is, 99.7% of events fall within +/-3σ. Thus, +/-3σ is a proxy for the flexibility requirements. Similarly, an increase in 3σ is one measure of the additional flexibility required due to the increased variability from intermittent resources.

The 3σ measure is used in Table 35, where the total and light load statistical results are revisited. The load and net load variability for each scenario, as well as the difference between them, is displayed in each set of rows. The first three columns show the total standard deviation (σ) of the 1-hour, 5-minute and 1-minute deltas. The final three columns show the light load standard deviation (σ) of the 1-hour, 5-minute and 1-minute deltas. The variability due to load alone is reported as well as the increase in variability due to intermittent renewables. In each comparison, the incremental requirement is based on the change in 3σ.

**Table 35. Total and Light Load Change in Flexibility Requirements.**

| | Total | | | Light Load (10th Decile) | | |
|---|---|---|---|---|---|---|
| | **σ 1-Hour Δ (MW)** | **σ 5-Min Δ (MW) (1)** | **σ 1-Min Δ (MW) (2)** | **σ 1-Hour Δ (MW)** | **σ 5-Min Δ (MW) (1)** | **σ 1-Min Δ (MW) (2)** |
| 2006 Load | 1,436 | 189.3 | 44.8 | 669 | 86.5 | 40.8 |
| 2006 L-W-S Change | 15 (+1%) | 0.3 (+0.2%) | 0.1 (+0.2%) | 30 (+4%) | 2.7 (+3%) | 0.1 (+0.2%) |
| **Increased Need (3σ)** | **45** | **0.9** | **0.3** | **90** | **8** | **0.3** |
| 2010 Load | 1,575 | 207.6 | 49.1 | 734 | 94.9 | 44.8 |
| 2010T L-W-S Change | 48 (+3%) | 6.9 (+3%) | 1.6 (+3%) | 199 (+27%) | 14.2 (+15%) | 1.1 (+3%) |
| **Increased Need (3σ)** | **144** | **21** | **5** | **597** | **42.6** | **3.3** |
| 2010 Load | 1,575 | 207.6 | 49.1 | 734 | 94.9 | 44.8 |
| 2010X L-W-S Change | 129 (+8%) | 14.2 (+7%) | 3.3 (+7%) | 347 (+47%) | 19.8 (+21%) | 2.9 (+7%) |
| **Increased Need (3σ)** | **387** | **42.6** | **9.9** | **1041** | **59.4** | **8.7** |
| 2006 Load | 1,436 | 189.3 | 44.8 | 669 | 86.5 | 40.8 |
| 2010 Load Change | 139 (+10%) | 18.3 (+10%) | 4.3 (+10%) | 65 (+10%) | 8.4 (+10%) | 4.0 (+10%) |
| **Increased Need (3σ)** | **417** | **54.9** | **12.8** | **195** | **25.2** | **12** |

Notes: (1) 5-minute change in MW on 15-minute rolling average
(2) 1-minute difference in actual MW from 15-minute rolling average

Overall, the incremental variability due to the expected growth of intermittent renewables (i.e. the 2010T scenario) increases about ~3% across all time frames. The artificially accelerated case (i.e., the 2010X scenario) results in an overall increase in variability of about 7% to 8% across all time frames. During the lightest load periods, the requirements are lower but the relative impact of the intermittent renewables is greater.

### *6.2.1. Overall Requirements*

The first data column in Table 35 shows a progression of one-hour load and net load variability for the 2006 and 2010 scenarios. This column shows quantitatively the increasing requirements for overall flexibility in hourly scheduling. The expected hour-to-hour change increases with load growth and with the addition of intermittent renewables.

In this time frame, the basic level of flexibility required to serve load now is about 4,300 MW/hr. This is three times the standard deviation of load alone variability, or 3 x 1,436. The 2006 intermittent renewables increase that requirement slightly to 4,353 MW/hr. The system load growth to 2010 drives the load alone variability requirement up to 4,725 MW/hr, which is an increase of about 400 MW/hr due to load. The expected growth of intermittent renewables, represented by the 2010T scenario, further increases the hourly flexibility requirement to 4,869 MW/hr, an increase of 144 MW/hr or about 35%.

By 2020, the increase in load has driven the load alone flexibility requirement (Table 10 in Section 3.0) up to about 6,000 MW/hr. With intermittent renewables, a further increase of 126 MW/hr appears.

In the artificially accelerated 2010X case, the high level of intermittent renewables outpaces load growth. Thus, the hourly flexibility requirement increased another 387 MW/hr to 5112 MW/hr.

The time relationship of the change in variability is shown in Figure 164**.** The lower trace (dark blue line) shows the expected increase in hourly variability due to load growth from 2006 to 2020. The upper trace (pink line) shows the increase due to both load and the expected intermittent renewable growth (2010T, 2020). For this expected trajectory, load dominates the increasing requirement. The impact of the intermittent renewables in 2010T is about 1/3 of the load impact, and the intermittent renewable impact in 2020 is about 10%of the load impact.

The increase in the hourly requirement (i.e., three times the difference between the two curves) is about 130 MW over all the years. In contrast, the increase due to load alone is about 1,700 MW (i.e., three times the difference in load alone hourly delta from 2006 to 2020). The impact of accelerated addition of intermittent renewables appears as the single point (orange square) for 2010X. This confirms that a faster growth of renewables will advance the timing of increased flexibility requirements.

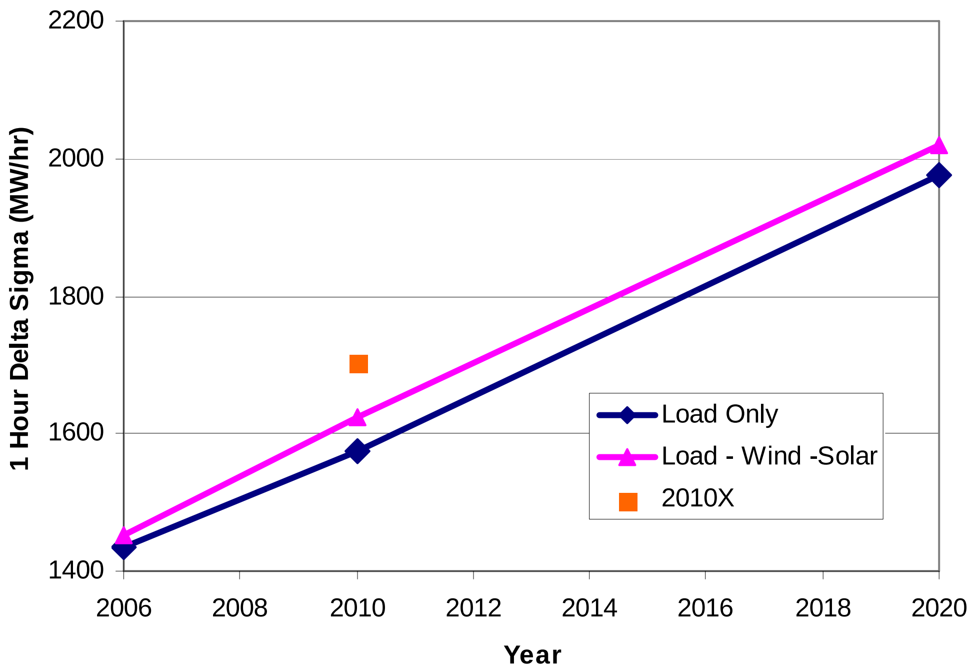


**Figure 164. Standard Deviations of Hourly Deltas.**

The second and third data columns of Table 35 show similar trends for sub-hourly variability. The 2006 5-minute requirement is 568 MW per 5-minutes (i.e., 3 x 189.3), with essentially no overall impact from wind and solar. Load growth to 2010 increases this requirement to 623 MW per 5-minutes, an increase of 54.9 MW per 5-minutes or about 10%. The incremental requirement due to intermittent renewables adds up to 42.6 MW per 5-minutes (about 8%) for a total of 665 MW per 5-minutes. The results are similar for regulation requirements.

Figure 165 shows the annual change in the standard deviations in the three time frames. The changes due to wind and solar generation for the 2006, 2010T and 2010X scenarios as well as the change due to load alone (2010) are shown. The magnitude of the impact of intermittent renewables is less than that of the load changes across all time frames.

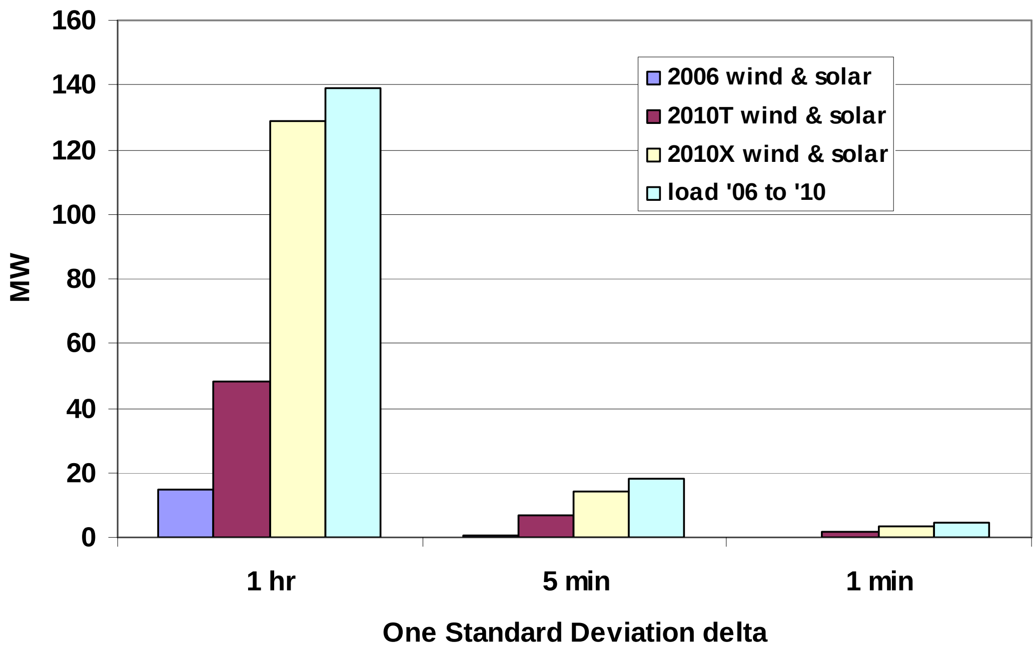


**Figure 165. Annual Standard Deviation Changes.**

The hourly and 5-minute requirements can also be compared. Overall, the load-following requirement (i.e., three times the standard deviation) will grow to about 600 MW to 700 MW per 5-minutes. Note that the schedule flexibility requirement is about 5,000 MW per hour. Assuming linearity, this is about 400 MW per 5-minutes. By definition, multiple periods of 3σ change would not be expected. Therefore, the requirement for 600 MW to 700 MW per 5-minutes, or about 130 MW/minute, is statistically consistent with the hourly requirement.

### *6.2.2. Light Load Requirements*

At light load, the requirement for schedule flexibility is lower, but the *relative* impact of intermittent renewables is higher. The three right data columns in Table 35 show the changes in flexibility requirement for the light load conditions in 10% of the year (i.e., 10$^{th}$ decile). In 2006, the light load hourly schedule requirement due to load alone is about 2,000 MW/hr. In 2010, the light load requirement is about 2,200 MW/hr, growing to about 3,000 MW/hr in 2020. With intermittent renewables, the requirement grows to about 4,000 MW in 2020. Note that this light load requirement is much less than the overall requirement of about 6000 MW/hr.

Figure 166 shows the growth in hourly variability at light load. The lower trace (dark blue line) shows the expected increase in hourly variability due to load growth from 2006 to 2020. The upper trace (pink line) shows the increase due to both load and the expected intermittent renewable growth (2010T, 2020). The artificially accelerated 2010X scenario is represented by the orange square.

The hourly and 5-minute change in requirements due to load are about half of the overall levels. Intermittent renewables are responsible for the other half of the increase. Thus, the relative impact of intermittent renewables, primarily wind at light load, is greater during light load periods.

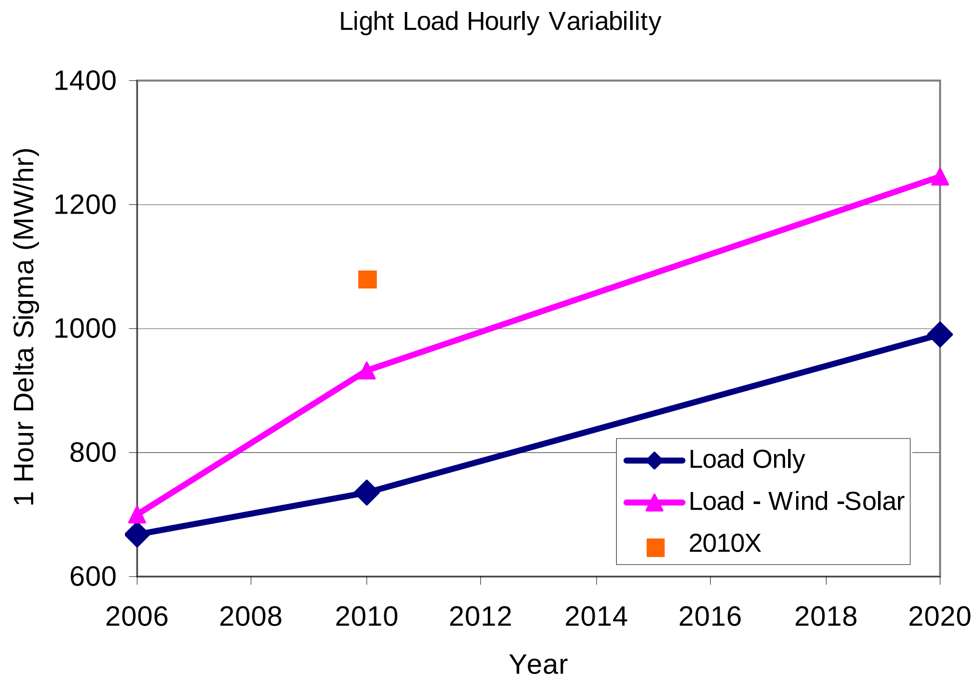


**Figure 166. Standard Deviations for One–Hour Deltas at Light Load.**

Similar observations apply to the load-following requirements, although the impact of wind is somewhat less. Specifically, the load alone requirement (i.e., 3σ) is 285 MW per 5-minutes under light load conditions, and 623 MW under all load conditions. With wind, the light load requirement is as much as 344 MW per 5-minutes, or about 70 MW/min. Again, this is still less than the overall requirement, but about 20% higher than the requirement for load alone.

Figure 167 shows the annual change in the standard deviations under light load conditions. The hourly changes are greater, but the light load requirement is still less than the overall requirement. However, providing this load-following capability in the down direction at light load may prove challenging for some operating conditions.

Unlike the longer time frames, changes in the standard deviation of regulation (i.e., 1-minute) is not affected by load level.

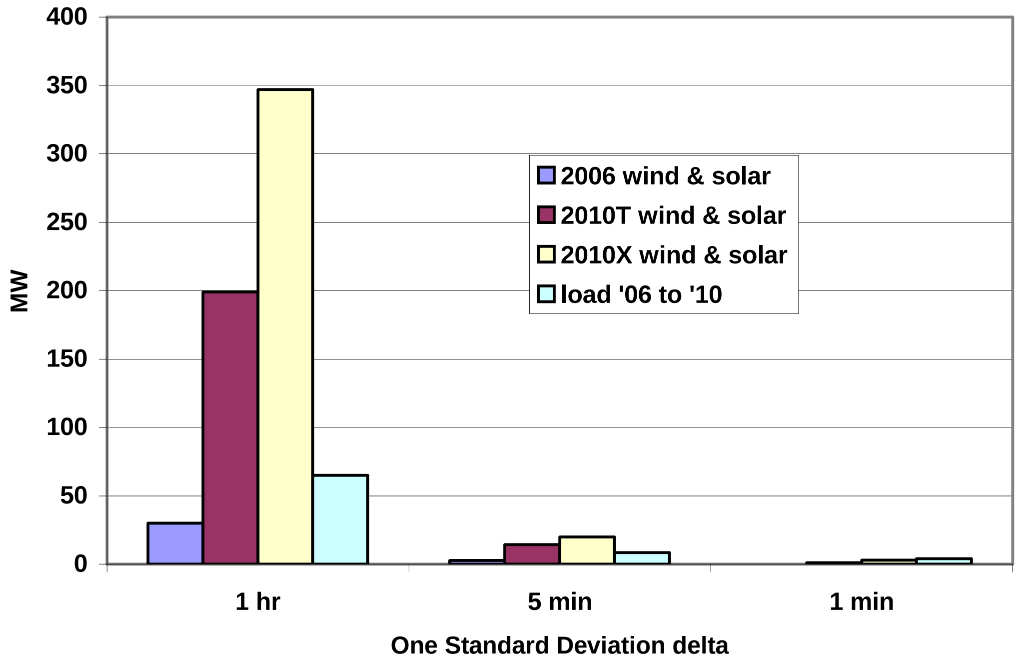


**Figure 167. Light Load Standard Deviation Changes**

### 6.2.3. Extremes

Table 36 summarizes the hourly load and net load variability for the 2010T, 2010X, and 2020 scenarios. The load and net load variability for each scenario, as well as the difference between them, is displayed in each set of three rows. The 1-hour standard deviation is shown, as well as the largest single load increase and decrease.

In general, the trends in the maxima and minima are similar to those observed in the more statistically meaningful standard deviation. Hence, a study approach based on individual worst cases has some intuitive appeal. However, reliance on a single data point is problematic. For example, the maximum 2010T net load 1-hour delta is about 400 MW less than the 1-hour delta of the 2010 load alone. A study approach based on extremes would conclude that the net load requirement should be less than the load alone requirement. Thus, a statistical outlier has distorted the results, and therefore, the conclusions.

**Table 36. Total Variability from Statistical Analysis.**

| | σ 1-Hour Δ | Maximum 1-Hour Δ | Minimum 1-Hour Δ |
|---|---|---|---|
| 2010 Load | 1575 MW | 6714 MW | -5617 MW |
| 2010T L-W-S | 1623 MW | 6312 MW | -5713 MW |
| **Change** | **48 MW** | **-402 MW** | **-96 MW** |
| 2010 Load | 1575 MW | 6714 MW | -5617 MW |
| 2010X L-W-S | 1704 MW | 7219 MW | -5986 MW |
| **Change** | **129 MW** | **505 MW** | **-369 MW** |
| 2020 Load | 1977 MW | 8427 MW | -7049 MW |
| 2020 L-W-S | 2019 MW | 8747 MW | -7351 MW |
| **Change** | **42 MW** | **321 MW** | **-302 MW** |

## 6.3. Operational Flexibility

In this section, the system-wide maneuverability requirements are examined in the forecasting, day-ahead unit commitment and dispatch, hourly schedule, 5-minute load-following and 1-minute regulation time frames.

### 6.3.1. Forecasting

The distinction between variability and uncertainty was discussed in Section 3.5. By nature, both system loads and intermittent renewables vary. Therefore, much of this study focused on the impact of intermittent renewable variability relative to load variability. The power system's response to this variability depends upon the capability of the available resources. One important aspect of this response is knowledge, a priori, of the output requirement. In general, a more unpredictable variation requires more agile generating resources.

Load and wind forecasting (Section 5.0) have a significant impact on system operating costs. Figure 168 shows a mix of historical load forecasts from the  California ISO, and wind forecasts developed for this study. The four upper curves represent actual load, hour-ahead load forecast, day-ahead load forecast and two day ahead load forecast. The lower curves represent the actual wind and day-ahead wind forecast. This figure validates both the analytical approach and the recommendations for flexibility in multiple time frames.

Note that the accuracy of the load forecast improves as the time horizon decreases. Further, the amplitude of the forecast error is somewhat correlated to the load magnitude. The detailed forecast error statistics (Section 3.0) confirm this. The wind forecast error, on the other hand, is not correlated to system load, but rather has some correlation to the wind power. From an operational perspective, this difference is important. Overall, the day-ahead forecast including wind and solar introduces about twice the uncertainty as the load forecast alone. However, significant errors in wind forecast at low load periods have a larger impact relative to the balance of generation available. The uncertainty due to intermittent renewables can be three times greater than the uncertainty due to load alone at moderate to light load levels.

The introduction of intermittent renewables tends to make the amplitude of operations uncertainty less correlated to load level. The statistical analysis shows that a range of about +/-5,000 MW bounds the day-ahead uncertainty with intermittent renewables. However, as the operational hour approaches, uncertainty in both the load and renewable generation forecasts drops considerably. The forecast statistics (Section 3.0) show that intermittent renewables increase the hour-ahead uncertainty about 20% over the load alone uncertainty. A range of +/-2,000 MW bounds the hour-ahead uncertainty with intermittent renewables.

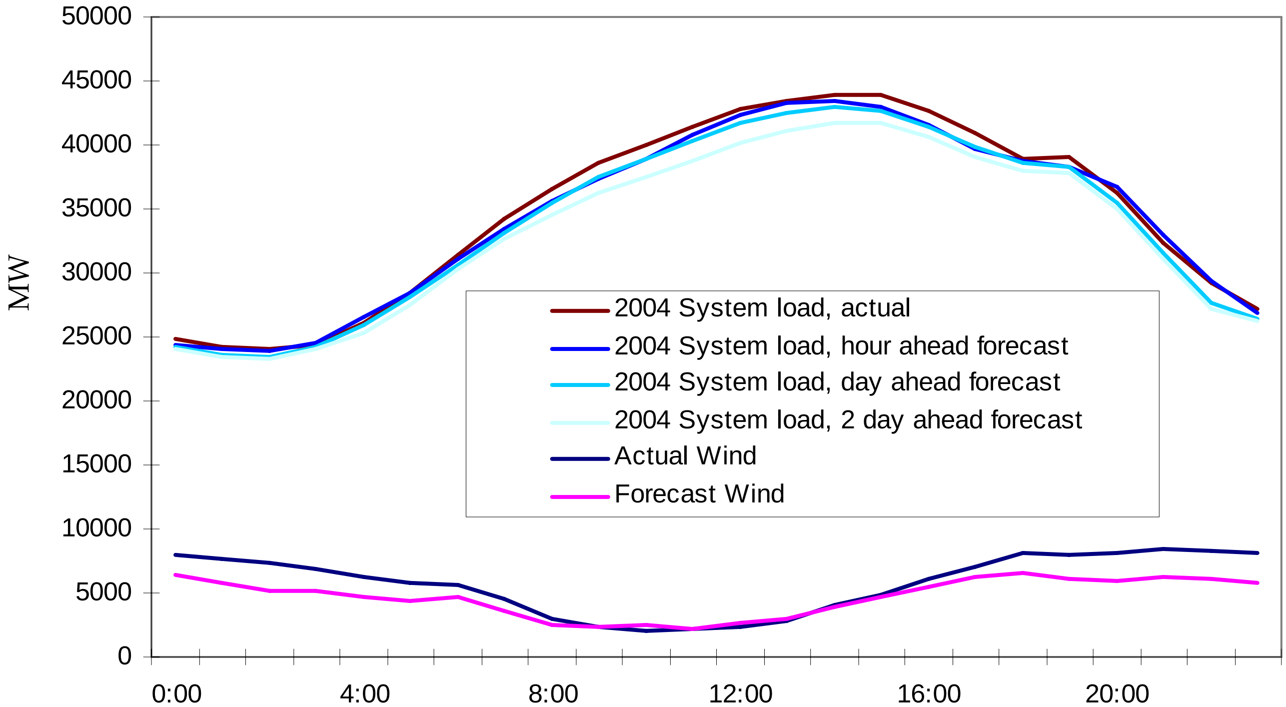


**Figure 168. Comparison of Historical Forecast and Actual Load and Simulated Day-Ahead Forecast and Actual Wind.**

### *Implications of Ignoring Forecasts*

System operations already face load forecast uncertainty. An imperfect load forecast, as well as an imperfect intermittent renewable forecast, plays a critical role in secure and economic operation of systems. Systems with small amounts of intermittent renewables can largely ignore them in day-ahead operations. As the penetration of intermittent renewables increase, however, such a practice becomes untenable.

Figure 169 shows an "open-high-low-close" stock chart of the 2010X day-ahead hourly load and net load forecast errors when both wind and solar forecasts are ignored. In all operating time frames, but especially under light load conditions, ignoring state-of-the-art forecasts has a huge impact on the net load forecast errors. All statistical quantities (average, standard deviation, extremes) are significantly increased. As noted above, the standard deviation of the load alone forecast error for the 10th decile is 570 MW. The net load forecast error reaches into the 6,000 MW to 8,000 MW range, with even greater outliers. The economic analysis (Section 4.2) showed that the economic penalty, in terms of operational inefficiency, completely swamps any benefits due to the addition of the renewables. The penalty is measured in the billions of dollars.

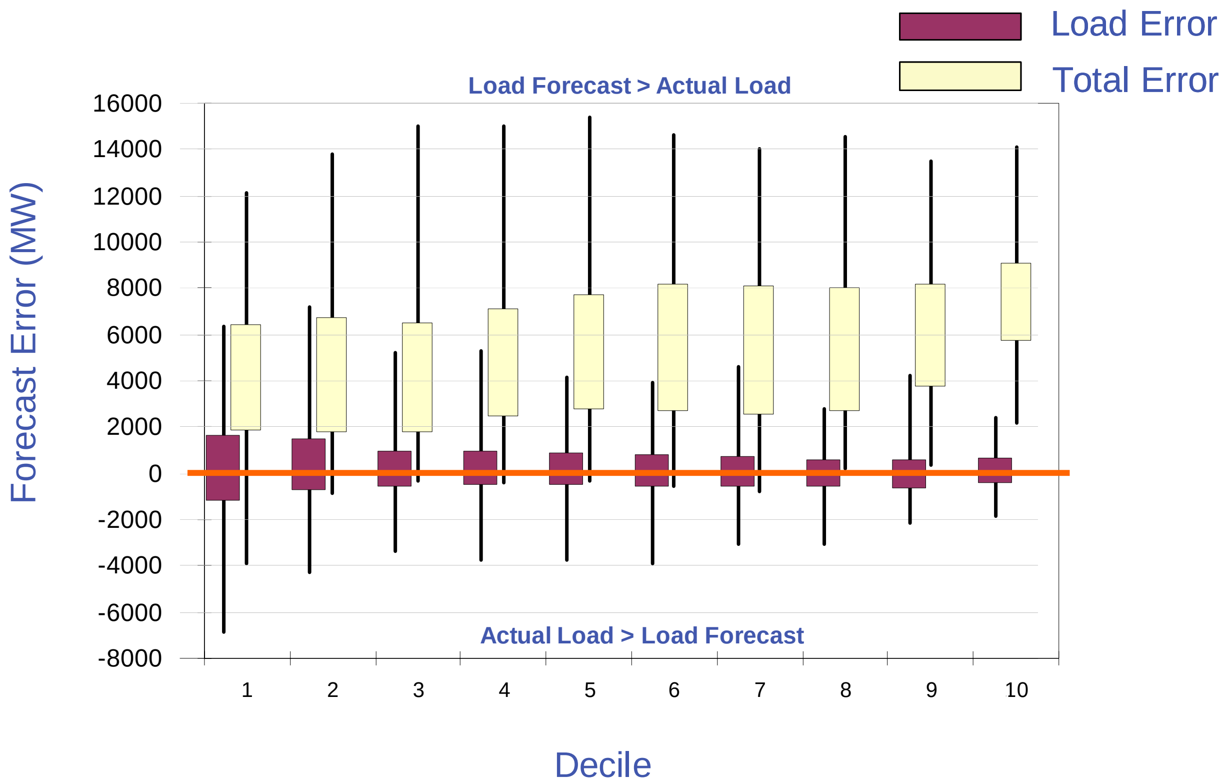


**Figure 169. 2010X Load and Net Load Day-Ahead Forecast Error Ignoring Wind and Solar Forecast Stock Chart by Decile.**

### *6.3.2. Unit Commitment and Schedule Flexibility*

The impact of intermittent renewable generation on hydro operation and the available dispatch range are discussed in the following sections.

#### *Hydroelectric Generation Shift*

Results of the production simulation analysis (Section 4.0) supported by the QSS analysis(Section 5.0) show that hydro operation plays an important role for operation with significant intermittent renewable generation. The ability to modify the hydro dispatch with small economic penalty makes it a natural counter to variation from intermittent renewables. The production simulation results showed that hydro operation within the state produces the same amount of energy, but is temporally shifted with the addition of wind and solar generation.

The number of hours of hydro displacement for a single year is shown in Figure 170. The red bar shows the number of hours with a displacement greater than 500 MW, the yellow bar shows the hours with a displacement greater than 1,000 MW, and the light blue bar shows the hours with a displacement greater than 1,500 MW. The majority of the hours in a year have a displacement less than 500 MW and are not shown in this figure. Note that the change in hydro operation is greater than 1,000 MW about 8% of the time in the 2010X scenario and only 3.5% of the time in the 2010T scenario. The conventional hydro should have the capability to provide this maneuverability, particularly when augmented by the available pumping loads.

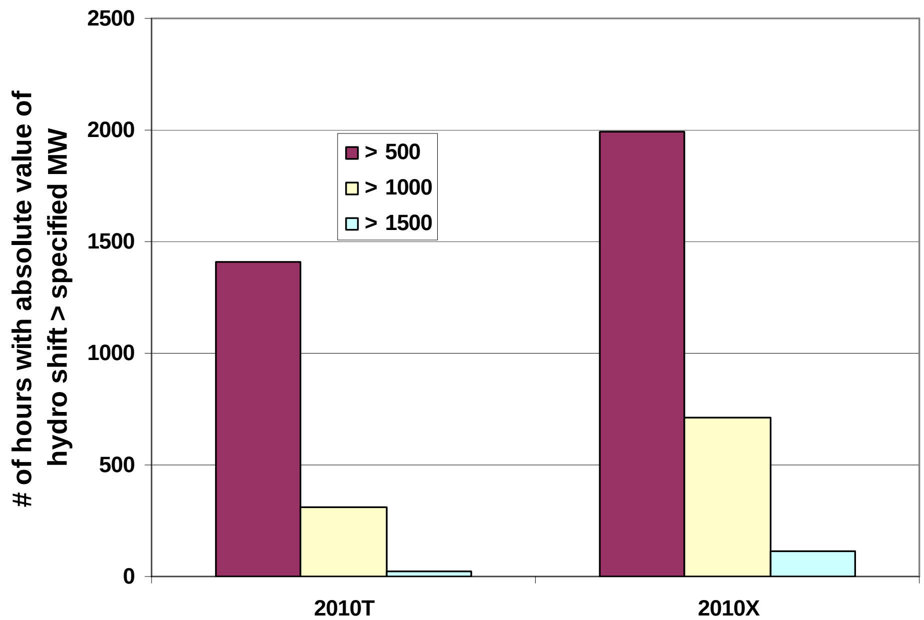


**Figure 170. Intermittent Generation Impact on Hydro Operation.**

### *Available Dispatch Range*

The production simulation analysis (Section 4.4.3) showed the distribution of available dispatch range, both up and down, as a function of system load. Figure 171 is based on the same year of data, but is presented as a function of time-of-day. The first group of traces shows the maximum and minimum (solid blue lines) and the average available (dotted blue line) up dispatch range. The second group of traces shows the maximum and minimum (solid orange lines) and the average available down dispatch range (dotted orange line). The third group of traces shows the hourly change in net load (load minus wind minus solar) for the 2010X case. The solid green lines are the maximum and minimum and the dotted green line is the average.

The plot shows the expected tendency for lower down range at light load and lower up range at high load. In addition, there are few points at which the extreme requirement (maximum or minimum of the green lines) impinge on the corresponding least flexible day of the year for a given hour. Periods of extreme morning and evening load rise present some risk. However, it is important to note that no *simultaneous* extremes ever occurred in the data. It is unlikely for the up range requirement to exceed capability. Similarly, extreme hours with the least range down capability occur during late evening and early morning hours. As with the range up, no *simultaneous* extremes ever occurred in the data. Again, the requirement is unlikely to exceed capability.

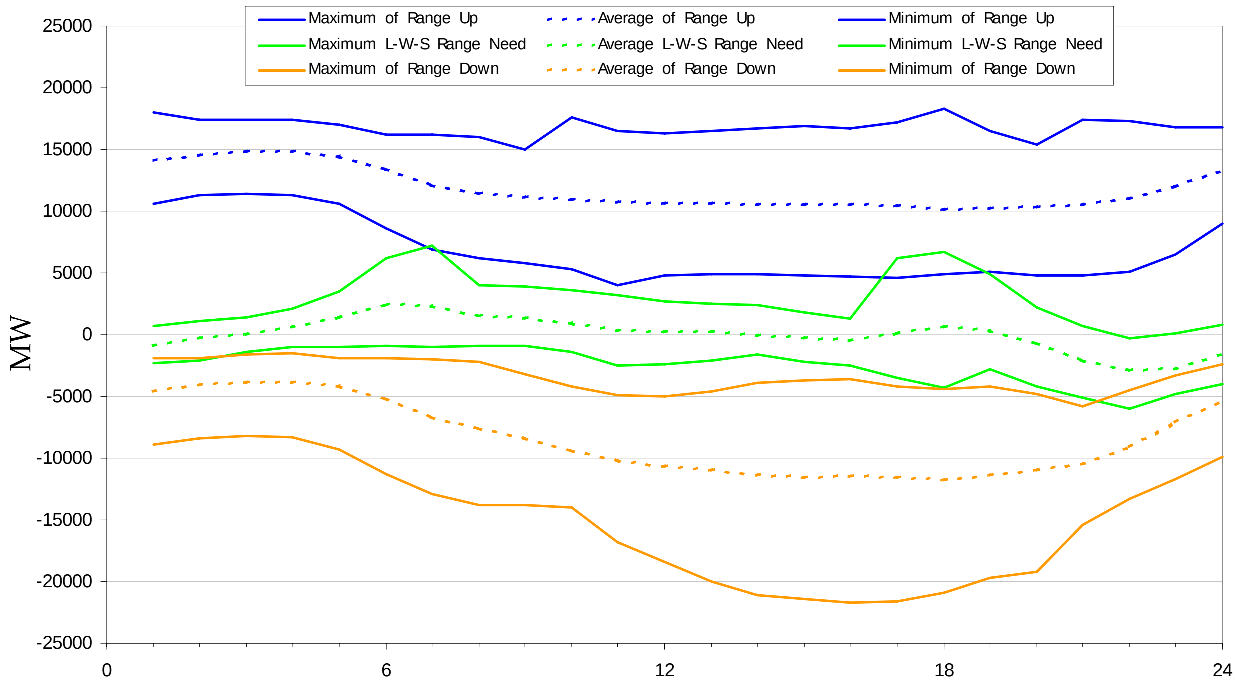


**Figure 171. Committed Generation Range and Maximum Hourly Net–Load Change.**

### *6.3.3. Load-Following*

The production simulation results used to create Figure 171 also produced measures of available ramping capability. Figure 172 presents the ramping capability and requirements in a similar fashion. This figure shows the maximum, minimum, and average of the up (blue lines) and down (orange lines) ramping capability in MW/min. The requirement traces are derived and presented slightly differently. The solid green curve is the average ramping requirement for each hour, based on the net load variability of that hour. The requirement range (dotted green lines) is based on the overall load-following (5-minute delta) statistical variation: 3 x 5-minute $\sigma$ = 120 MW/min (i.e. 600 MW/5-minutes).

Note that typically the ramp capability greatly exceeds expected requirement. In addition, the extreme hours with the least ramp down capability occur during early morning hours. Figure 173 shows the same data as Figure 172, but with the vertical scale reduced to show the light load down ramping capability constriction. During early morning hours the available ramp down capability on the limiting day just meets the requirements. Again, no *simultaneous* extremes ever occurred in the data, and the requirement is unlikely to exceed capability.

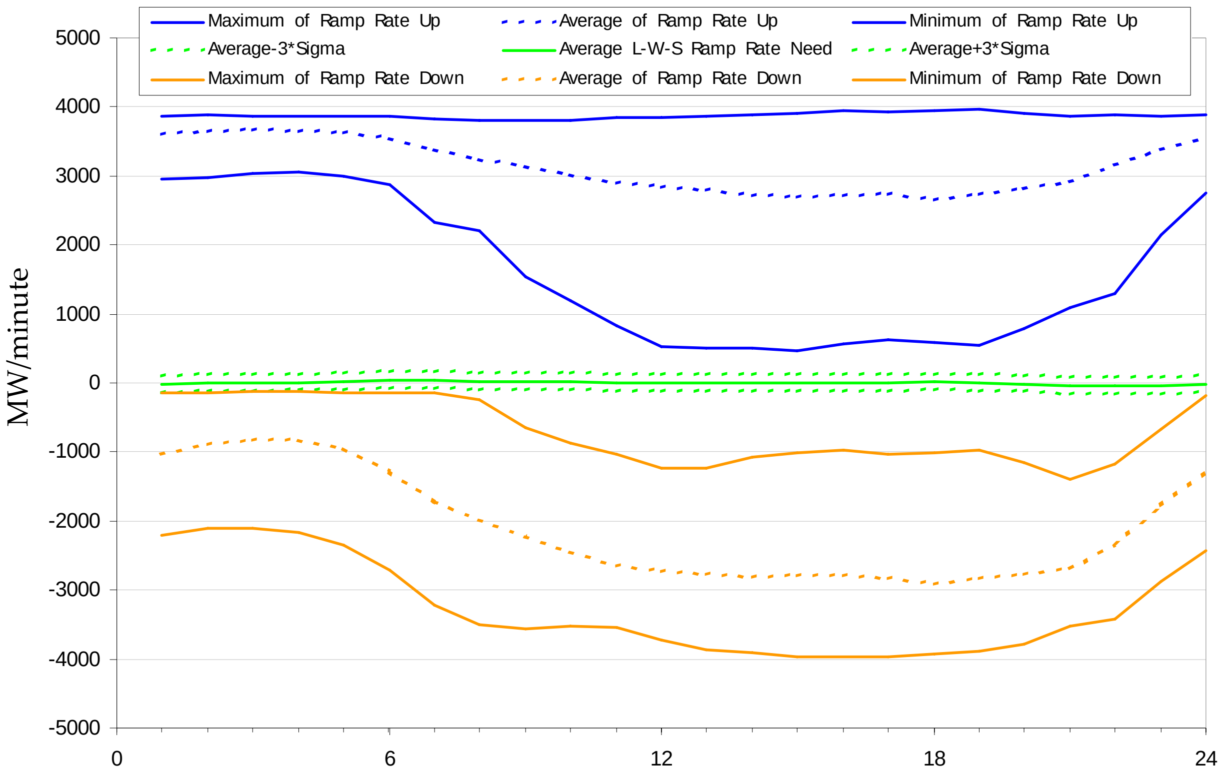


**Figure 172. Committed Generation Ramp Rate Capability and Expected Load–Following Duty.**

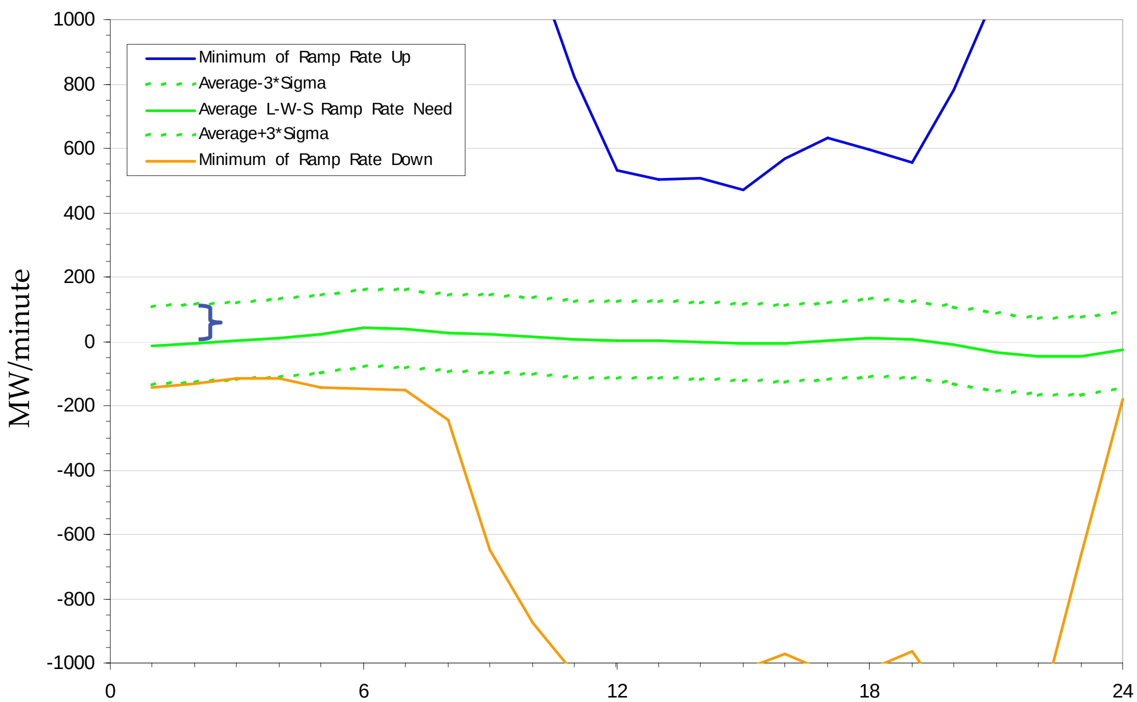


**Figure 173. Expanded View of Committed Generation Ramp Rate Capability and Expected Load–Following Duty.**

### *Impact of Pumps on Load-Following*

The statistical, production simulation and QSS analyses all showed that pumps, be they DWR pumps or pumped storage hydro pumps, can have a significant impact during light load periods. The relative impact of pump switching and wind variability on load-following is illustrated in Figure 174 and Figure 175.

Figure 174 shows the economic dispatch from a pair of QSS simulations for a May night. The blue trace shows the economic dispatch raise/lower signal (MW/min) for a case with constant wind output, and the orange trace shows the same signal for a case with variable wind. The variability in the blue trace is due only to the load, which includes pump switching events. The variability of wind (orange trace) increases the frequency with which the economic dispatch signal changes sign. Figure 175 shows the same pair of cases, except that the pump steps have been removed from the load profile. The behavior of the two cases shows less overall variability due to a less variable load profile.

Statistical measures were extracted from this set of four cases and are shown in Table 37. The impact of the pumps is larger than that of the wind, and the impact of the wind is relatively less in the more variable case. A further statistical examination of all light load data is summarized in Table 38. Under nominal light load conditions, wind variability increases load-following by about 20 MW/min, which is about the same as the contribution due to the pump steps.

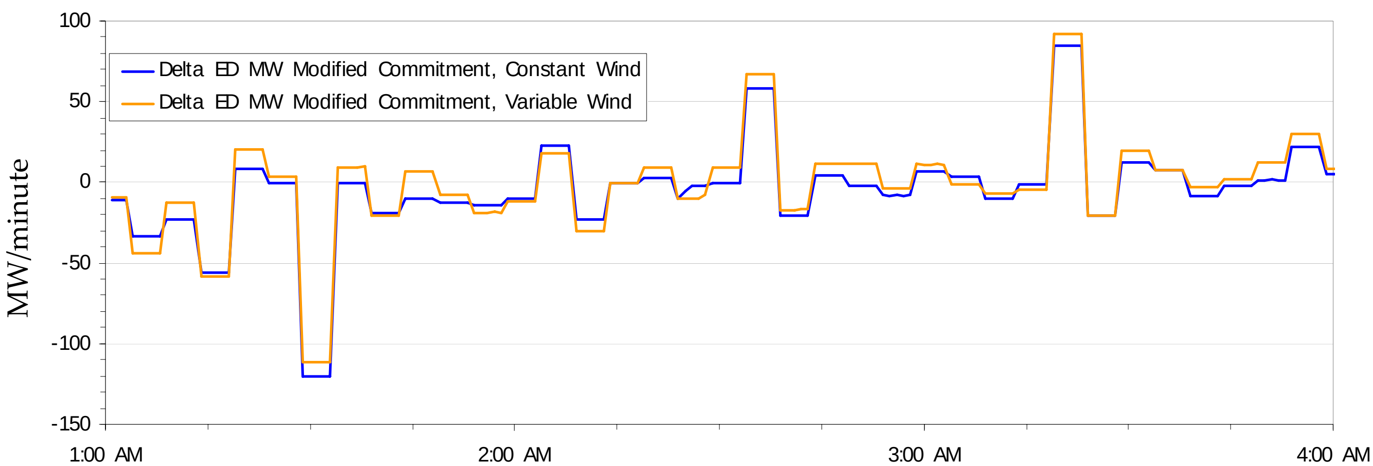


**Figure 174. Impact of Wind Variability with Pumps in Load Profile.**

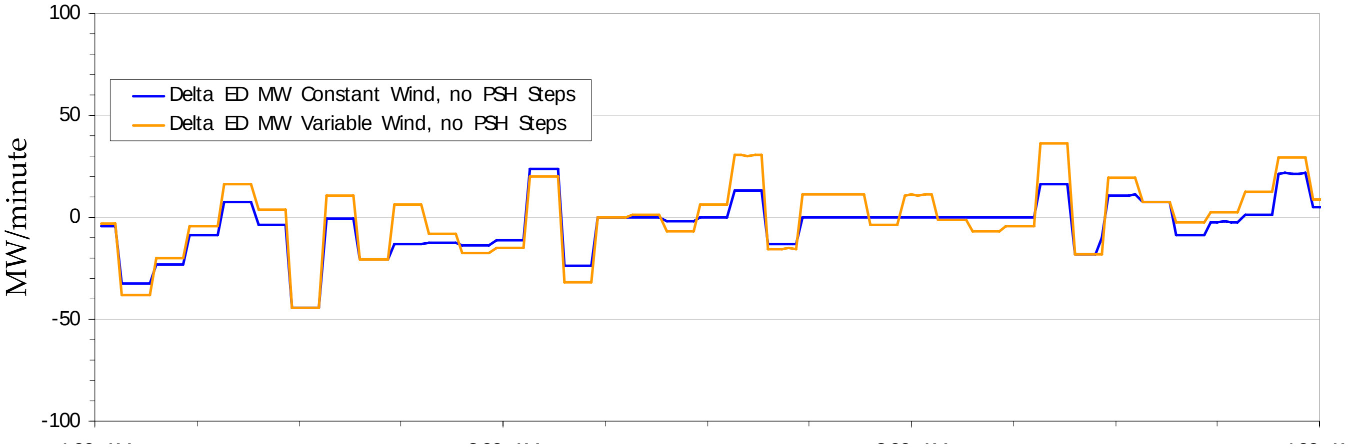


**Figure 175. Impact of Wind Variability Without Pumps in Load Profile**

**Table 37. Load–Following Statistics of QSS Pump and Wind Sensitivity Cases**

| | Without Pump Steps | | | With Pump Steps | | |
|---|---|---|---|---|---|---|
| | Constant Wind | Variable Wind | Change | Constant Wind | Variable Wind | Change |
| σ Delta ED | 14 MW | 18 MW | 29% | 30 MW | 32 MW | 7% |
| Zero Crossings | 11 | 21 | 91% | 19 | 21 | 11% |

**Table 38. Load–Following Statistics of Light Load Conditions for Pump and Wind Sensitivity**

| | Without Pump Steps | | | With Pump Steps | | |
|---|---|---|---|---|---|---|
| | Load | L-W-S | Change | Load | L-W-S | Change |
| σ 5-Minute Δ in $10^{th}$ Decile | 75 MW | 110 MW | 47% | 95 | 115 | 21% |

### *Implied Costs of Load-Following*

The production simulations show that economic operation of the system results in a unit commitment and dispatch with adequate load-following capability. Consequently, the economic impact of providing load-following is built into the economic dispatch.

It is, nevertheless, an interesting exercise to postulate a separate load-following function that isolates the impact of the intermittent renewables from normal load-following and economic dispatch. This can be approximated by assuming that all incremental load-following requirements will be imposed on the regulation market.

The statistical analysis showed that the year round incremental load following requirement is 43 MW per five minutes (i.e. 3σ = 3 x 14.2 MW/5 minutes). If this incremental load following is assigned to regulation, then additional regulation capability must be procured to cover 5 minutes of incremental load following. Thus, 43 MW of up regulation and down regulation must be procured. At historical average regulation prices (from California ISO), this extra procurement costs $18.5M per year or 48¢/MWh, i.e. 43 MW x ($28/MW per hour up + $21/MW per hour down) x 8760 hr/year = $18.5M.

As noted, light load operating conditions potentially present the most challenging operating condition. If the incremental regulation requirement for only the light load (i.e., 10th decile) is considered, the implied costs are less. During light load, the incremental regulation requirement is 60 MW/5-minutes. Procurement of the extra regulation for only this lightest load period would cost $2.5M per year. The calculation is (3 x 19.8) x ($28 +$21) x 8760 X 0.1 = $2.5M, which works out to 40 ¢/MWh of wind power produced during the 10th decile.

Another mechanism to provide operational flexibility is selective curtailment. Although the statistical and production simulation results suggest that curtailment is unlikely to ever be necessary for an economically operated system, curtailment would tend to result in wind energy loss during periods of low spot price. The cost implications of such a curtailment can be estimated. For example, a 5% curtailment during all minimum load periods would result in ~300,000 MWh of lost wind production. Since the average spot price is ~ $23/MWh, this results in an annual cost of about $7M, or 18 ¢/MWh of wind production.

### 6.3.4. Regulation

The impact of pumps on regulation, the impact of intermittent renewables on CPS2, and the implied costs of regulation are discussed in the following sections.

#### Impact of Pumps on Regulation

The previous section compared the impact of pumps and intermittent renewables on load-following in light load periods. The relative impact of pump switching and wind variability on regulation is illustrated in Figure 176 and Figure 177.

Figure 176 shows the regulation duty from a pair of QSS simulations for a May night. The blue trace shows the regulation (MW) for a case with constant wind output, and the orange trace shows the same signal for a case with variable wind. The impact of the wind variability is visible, but relatively small compared to the pump switching events which are the three large excursions at about 1:30, 2:30 and 3:15. Figure 177 shows the same pair of cases, except that the pump steps have been removed from the load profile. The impact of the wind is more visible.

Statistics for these QSS cases are summarized in Table 39. A further statistical examination of all the light load data is summarized in Table 40. Under nominal light load conditions, wind variability increases overall regulation by about 10%, about the same as the variability due to switching pumps.

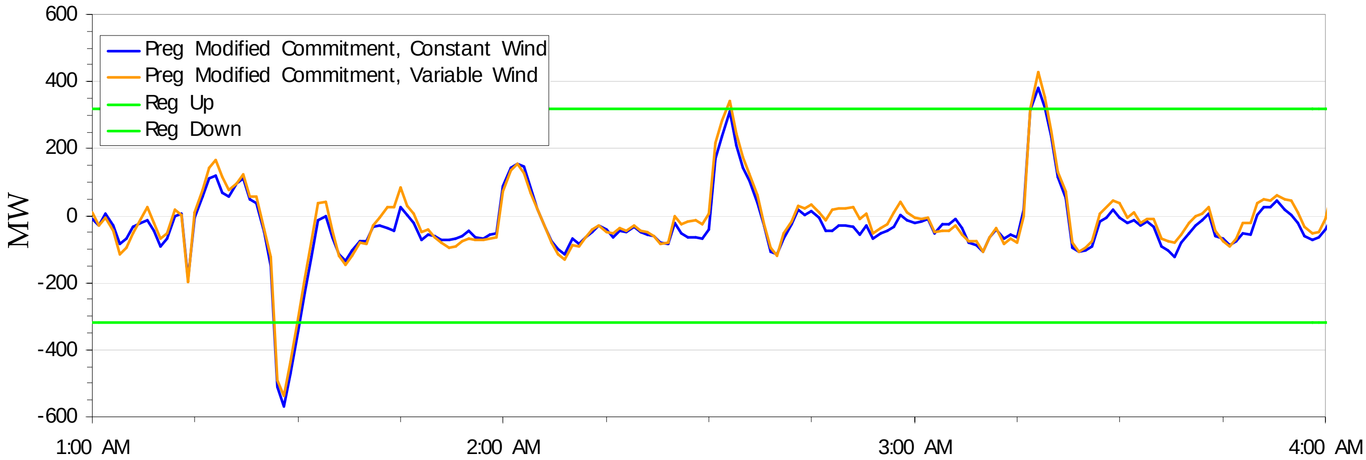


**Figure 176. May Night: Impact of Wind Variability with Pump Steps**


**Figure 177. May Night: Impact of Wind Variability Without Pump Steps**

**Table 39. Regulation Statistics of QSS Pump and Wind Sensitivity Cases**

| | Without PSH Steps | | | With PSH Steps | | |
|---|---|---|---|---|---|---|
| | Constant Wind | Variable Wind | Change | Constant Wind | Variable Wind | Change |
| σ Preg | 60 | 68 | 13% | 111 | 114 | 3% |

**Table 40. Regulation Statistics of Light Load Conditions for Pump and Wind Sensitivity**

| | Without PSH Steps | | | With PSH Steps | | |
|---|---|---|---|---|---|---|
| | Load | L-W-S | Change | Load | L-W-S | Change |
| σ 1-Minute Δ in $10^{th}$ Decile | 33.7 | 40.9 | 22% | 38.6 | 42.3 | 10% |

### *CPS2 Discussion*

The NERC Control Performance Standard 2 (CPS2) is the US industry standard metric for determining control area adherence to scheduled interchange and frequency. In broad terms, CPS2 allocates responsibility for regulating frequency and interchange according to the size of a control area [9]. CPS2 is a highly non-linear function, which allows deviation within a band around the schedule. Larger control areas are allowed greater deviation from schedule, with the understanding that they bear a greater burden and responsibility to participate in the secure and stable operation of the system.

CPS2, given in %, is normally compiled on a monthly basis. A CPS2 performance of 100% means that the area control error (ACE) never went outside the allowed band. NERC criteria require CPS2 performance of at least 90%. In most systems CPS2 is higher than 90%, i.e., performance is better.

Fundamentally, CPS2 adherence requires adequate regulation capability to accommodate fast net load variability and meet the interchange schedule. For instance, low load variability, sufficient available regulation and no schedule changes will ensure compliance. By contrast, high load variability with insufficient available regulation *or* significant schedule changes will violate criteria.

Four assumptions are required to perform a statistical estimation of the impact of increased variability on CPS performance. They are:

- All CPS2 violations are due to load or net load variations
- Load and net load variability distributions are normal
- Interchange schedule remains fixed
- Regulation resources and strategy are unchanged

With these assumptions, CPS2 performance corresponds to a symmetric confidence interval in the standard normal distribution of load only variability. For example, 90% CPS2 performance corresponds to a 90% symmetric confidence interval. By applying Chebyshev's Theorem it is then possible to calculate the narrowing of the confidence interval associated with the more variable net load distribution. This provides an estimate of the new CPS2 performance.

Throughout this study, the 1-minute delta was used as a measure of the fast variability. Therefore, the statistical distributions of the 1-minute deltas are reasonable proxies for anticipated change in CPS2.

For the projected renewables growth (2010T), the increase in 1-minute delta $\sigma$ due to intermittent renewables is 1.6 MW/min (from 49.1 MW/min to 50.7 MW/min). The change in expected CPS2 performance for this scenario is as follows:

- 90% CPS2 would be expected to decline to 88.9%
- 95% CPS2 would be expected to decline to 94.2%.

For the artificially accelerated 2010X scenario, the increase in 1-minute delta σ due to intermittent renewables is 3.3 MW/min (from 49.1 MW/min to 52.4 MW/min). The change in expected CPS2 performance for this scenario is as follows:

- 90% CPS2 would be expected to decline to 87.7%
- 95% CPS2 would be expected to decline to 93.3%.

Therefore, CPS2 performance would be expected to decline approximately 1% to 2% due to the increase in fast variability without additional regulation.

If the existing CPS2 is at least 92.2%, then no additional regulation is required to meet the 90% criteria under the 2010X scenario. If the existing CPS2 is at least 91.1%, no additional regulation is required to meet the 90% criteria for the 2010T scenario.

Some systems are known to hold their CPS2 performance levels far above that required by NERC operating standards. However, there is a significant operational cost associated with maintaining a higher than required level of performance. The need to incur such operating costs should be examined. Further, CPS2 violations driven by hourly schedule changes could be reduced by modifying scheduling practice.

#### *Implied Costs of Regulation*

The statistical analysis shows an increase of 20 MW in regulation requirement. As noted in Section 6.1, this is small compared to the range of regulation regularly procured, which is roughly 300 MW to 600 MW. The average cost of regulation, per California ISO data, is $28/MW up and $21/MW down. Thus, the cost to procure one MW-yr of up regulation is about $245,000, and one MW-yr of down regulation is about $184,000. To procure an additional 20 MW in each direction would cost a total of $8.6M/year, or 22¢ /MWh of intermittent renewable energy.

## 6.4. Mitigation Methods

In this section, selected mitigation options are examined further. These mitigation options are primarily focused on the adverse implications of variability in a given time frame.

### *6.4.1. Unit Commitment and Schedule Flexibility*

The QSS May example (Section 5.2.2) showed that changing the commitment by substituting maneuverable units for fixed dispatch units would increase available range. Wind curtailment was also shown to increase available range. However, there are cost trade-offs between the modified commitment and wind curtailment mitigation methods. De-committing a base-load unit may mean that it will be unavailable during the next high load period and beyond. In that case, short-term wind curtailment will probably be the lower total cost option. Conversely, de-committing base-load units may be more cost effective if the combined load and renewable forecast indicates an extended period of significant wind energy curtailment.

Providing deeper runback capability also mitigates the light load maneuverability problem, and eliminates the curtailment/de-commitment decision. Generators realize further benefits by avoiding start/stop costs. As noted in Section 5.2.2, combined cycle power plants may present an opportunity for deeper runback. Similarly, energy storage reduces the need for other mitigation methods. Some storage technologies may also provide benefits in other time frames. The use of pumped storage increased when conventional hydro flexibility decreased. It is possible that some variation within the day can be accommodated with gas storage in pipelines. Also, short-term modification of interchange schedule would provide similar benefits.

The need for these mitigation methods drops as load increases (Section 6.2).

### 6.4.2. Load-Following

The QSS June example (Section 5.2.3) showed that imposing short-term wind curtailment with a rate limit on recovery relieves temporary depletion of ramp down capability. The QSS May night example showed that curtailment can increase available ramp capability. Similarly, energy storage can increase available ramp capability. Variable speed pumped storage can provide ramp capability during pumping. Adding loads, e.g. increased participation of controlled pump loads, has similar benefits.

### 6.4.3. Regulation

The statistical analysis showed an increase in regulation requirement and the production simulation analysis showed a 1 MWh increase in gas turbine generation per 20 MWh of wind and solar energy. Since gas turbine (GT) usage is likely to increase with significant levels of intermittent generation, they may be able to provide regulation and load-following services as well.

Modern gas turbines have a minimum ramp rate of about 10% MW/minute from a cold start. They are also extremely flexible, with an operating range of 20% to 100% of nameplate. By contrast, a typical existing gas turbine has an operating range of about 50-100% of nameplate.

Table 35 shows a 1-minute 3σ increase of 10 MW/minute (i.e., regulation), and a 5-minute 3σ increase of 43 MW/ 5 minutes (i.e., load-following) for the accelerated 2010X scenario.

Therefore, 100 MW of new GT would cover the system-wide increase in regulation for the 2010X scenario, i.e., 10 MW/min regulation need / 10% MW/minute ramp rate = 100 MW. And, 54 MW of new GT would cover the system-wide increase in load following for 2010X, i.e., 43MW load following need / 80% MW operating range = 54 MW.

Thus, about 200 MW of new GT should meet all additional regulation and load following requirements for all study scenarios, provided that the hourly operation flexibility requirements are met by other means.

# 7.0 Conclusions and Recommendations

Four scenarios with increasing levels of intermittent renewable generation were evaluated in this study: 2006 (2,100 MW wind, 330 MW of solar), 2010T (7,500 MW wind, 1,900 MW solar), 2010X (12,500 MW wind, 2,600 MW solar), and 2020 (12,700 MW wind, 6,000 MW solar). The 2010T and 2020 study scenarios represent two steps on an expected trajectory to meet California's renewable generation goal (Section 2.1). The artificially accelerated 2010X scenario was developed to increase system stress and represents the most challenging study condition. However, the observations, conclusions and recommendations presented in this section apply to all scenarios, not just the most challenging. They are intended to enable consistent, sustained renewable growth through 2020.

## 7.1. Observations by Time Frame

The analytical work presented throughout this report produced extensive quantitative results. In this section, a largely qualitative synopsis of the key findings is presented to provide context for the conclusions and recommendations.

### *7.1.1. Day-Ahead and Overall Operation*

Intermittent renewable generation will displace other more expensive generation, i.e., generation with a higher marginal variable cost. Since natural gas combined-cycle power plants are frequently on the margin in WECC, most of the displaced generation is combined-cycle. Roughly half of the displaced generation is inside California and the other half outside (Section 4.4). The displacement of out-of-state generation by lower marginal cost in-state renewables is an economic benefit of the added renewables. This displacement is not an export of wind variability to neighboring systems.

Conventional hydroelectric facility operation within the state is temporally shifted due to wind and solar generation. However, the change in operation is less than 1,000 MW more than 90% of the time, on a hydro system with over 9,000 MW of capacity (Sections 4.4, 4.4.1). The conventional hydro facilities should be able to provide this maneuverability, particularly when augmented by the available pumping loads.

Day-ahead operations will be less certain as intermittent resources increase. Total load and intermittent renewable forecast errors will be roughly twice that of the load forecast error alone. This may increase the operation of peaking generation when other generation is under-committed due to over-forecasting of intermittent renewables. The increased use of peaking combustion turbines offsets some of the economic value of the intermittent renewables. This uncertainty was included in the analysis. System performance based on currently available load data and wind forecasting technology was satisfactory (Sections 3.5.1, 4.7). Substantial economic benefit will be realized with the use of day-ahead wind and solar forecasting in unit commitment and scheduling (Sections 4.3, 4.7).

### *7.1.2. Hourly Schedule Flexibility*

The requirements for hourly schedule flexibility increase over time due to both system load growth and additional intermittent renewables. Three times the standard deviation of one-hour change, which was the primary metric of required schedule flexibility, shows the relative impact of these two components. The increase in hourly variability due to load is substantially greater than the impact of wind and solar for the expected intermittent renewable scenarios (2010T, 2020). The load growth through 2020 continually increases the schedule flexibility requirement. The incremental requirement due to load growth from 2006 to 2020 is about 1,700 MW/hr. The intermittent renewables uniformly increase the schedule flexibility requirement above the load alone requirement by about 130 MW/hr for these scenarios (Sections 3.2, 6.2.1).

A comparison between the 2006 and the artificially stressed 2010X scenarios shows the increase in schedule flexibility requirement due to load alone is about equal to that due to the accelerated addition of intermittent renewables (Section 6.2.1).

The addition of zero marginal cost intermittent renewables will displace other generation with higher marginal operating costs. This means that the commitment and dispatch of the other generation resources necessary to provide operational flexibility will change. In general, the ability to dispatch down at light load and to dispatch up at heavy load represent the limiting conditions (Section 4.4.3).

Range (i.e., the remaining capacity (MW) available between the current operating point and either the maximum or minimum) measures the ability of the balance-of-portfolio (i.e., non-renewable) generators to respond to changing load, wind and solar conditions in the hourly time frame. The analysis of the available range to dispatch up at peak load showed no limitations. The available range to dispatch down at light load was also adequate. However, limitations may be encountered with coincident minimum load, high wind generation and low conventional hydro flexibility. Conventional and pumped storage hydro generation as well as pump loads play an important role in providing the necessary schedule flexibility (Section 6.3.2).

During daily real-time operation, the incremental hour-ahead uncertainty due to intermittent renewables is much less than day-ahead values. The combined hour-ahead forecast error is about 20% greater than that for load alone (Section 3.5.2).

The analysis found that a rational, i.e., least cost, dispatch and commitment of available resources results in satisfactory operation in this time frame (Section 4.7).

### *7.1.3. 5-Minute Load Following and Economic Dispatch*

An examination of the change in the standard deviations in the 5-minute time frame shows the relative impact of load growth and additional intermittent renewables on the load-following requirements. Load growth will increase the load-following requirement about 10% by 2010 and about 35% by 2020. The intermittent renewables will further increase that requirement by 3% to 7%. Although the relative increase is greater at light load, the light load requirement itself is less than the overall requirement (Sections 3.3, 6.2).

The load following capability at any given operating point is dictated by unit commitment and dispatch. Ramp rate capability (i.e., the speed (MW/minute) at which the system can use the remaining up and down range) measures the ability of the balance-of-portfolio (i.e., non-renewable) generators to respond to changing load, wind and solar conditions in the 5-minute time frame. The available ramping capability of on-line units, both up and down, was found to be largely adequate. Under light load conditions, various mitigation strategies (e.g., selective wind curtailment and thermal unit recommitment) were effective in relieving load-following limitations should they occur (Sections 5.2.2, 6.3.2). Throughout the analysis and results of this study, all intra-hour variability impacts of intermittent renewables are handled by in-state resources. Variability impacts are not exported to neighboring systems.

### 7.1.4. 1-Minute Regulation

The 1-minute variability also increases with load growth, and is further increased by the addition of intermittent renewables. On a percentage basis, the increase in regulation requirement due to load growth and due to intermittent renewables are similar to the load-following increases. Unlike the hourly and load-following time frames, however, regulation requirements are relatively uncorrelated to system load level. The increase in regulation requirement due to the intermittent renewables is about 3% to 7%.

Insufficient load-following capability increases the need for regulation capability. Rapid variation in load as well as intermittent renewable production will increase the area control error (ACE), which also drives a greater use of regulation. Any increase in ACE may degrade CPS2 performance. If no changes are made to the present regulation procurement, the impact on CPS2 is about 2% (Sections 3.3, 6.3.4, 5.2.3).

## 7.2. Conclusions

The 2010X scenario examined a total of 19,800 MW of renewables in California, including 12,500 MW of wind generation, 2,600 MW of solar, 1,000 MW of biomass and 3,700 MW of geothermal. This scenario represents a stressed condition designed to test the system with more renewables than projected for 2010.

This level of renewable generation can be successfully integrated into the California grid provided appropriate infrastructure, technology, and policies are in place. Specifically, this successful integration will require:

- Investment in transmission, generation and operations infrastructure to support the renewable additions,
- Appropriate changes in operations practice, policy and market structure,
- Cooperation among all participants, e.g., California ISO, investor owned utilities, renewable generation developers and owners, non-FERC jurisdictional power suppliers, and regulatory bodies.

## 7.3. Recommendations

The study scenarios represent stages along a trajectory to meet California's renewable generation goal. The following recommendations are a set of targets, actions and policies designed to ensure successful integration of significant levels of intermittent renewable generation through 2020. The implementation of these recommendations should proceed concurrently with the renewable generation growth. Such evolutionary improvements will allow secure and economic integration at all stages along the renewable generation growth trajectory.

The challenge of accommodating substantial intermittent renewable generation is incremental to the challenge of serving existing and new load. Long term planning must always consider requirements for generation and transmission, and strike an appropriate balance between the two. Further, new considerations specific to renewable technologies must be included. Thus, the planning process must consider three major system components:

- Generation
- Transmission
- Renewable Technology

The recommendations presented below are grouped accordingly.

### 7.3.1. Generation Resource Adequacy

The CEC, CPUC and California ISO have ongoing processes to provide the generation infrastructure necessary to maintain reliable operation. The addition of both intermittent and non-dispatchable renewable resources to the California grid increases the requirement for generation resource flexibility. It is essential that this requirement for flexibility be included in the overall assessment and planning for resource adequacy. It is recommended that specific attributes of generation flexibility be inventoried, maintained and increased. Where possible, quantitative targets are suggested; others may be adopted as circumstances and understanding changes. To avoid repetition, specific policy and technology recommendations are grouped with the most relevant performance issue. However, many recommendations could apply to a broader range of performance categories. Further, none of the recommendations are either self-sufficient or mutually exclusive. An appropriate combination of means will be most successful.

*Minimum Load Operation.* The California grid should target a combination of in-state generating resources and power exchange capability/agreements with neighboring systems that allow operation down to a minimum net load (load minus wind minus solar) in the range of 18,000 MW to 20,000 MW. These targets will meet the long-term (2020) needs of the system, and allow for operation with minimal curtailment of intermittent renewables (Section 3.1.3).

> *Minimum Turndown.* Generating resources with lower minimum power output levels provide greater flexibility, and allow successful operation at minimum load. New generating resources should be encouraged and/or required to have this capability; existing generation should be encouraged and/or required to upgrade their capability. A comparison of the load and net load (load-wind-solar) for the various scenarios shows that minimums are less with the intermittent generation on the system. The minimum system turndown capability will determine the amount of renewable generation curtailment that is necessary. A minimum of 20,000 MW is expected to result in curtailment during a few hundred hours per year for the expected growth trajectory (Sections 4.4.2, 3.1.3).

*Diurnal Start/Stop*. Another way to meet minimum load is to increase the amount of generation that is capable of reliable diurnal cycling. This will benefit the system by allowing the commitment of units that are economic at peak and shoulder loads, without requiring their non-economic operation at light load (Section 4.2).

*Load Participation*. Active participation by large loads, especially pumps, is another way to assure adequate flexibility. The pumps controlled by California Department of Water Resources are already participants in the energy market, but additional types of participation and cooperation could increase overall system flexibility. For example, additional investment in pumps, controls or other load infrastructure to take advantage of light load energy pricing could be both economic and effective [8], (Sections 5.2.2, 6.3.4).

California should explore other means to encourage load shifting towards light load conditions. Various load shifting and storage technologies, such as cold storage (e.g. for building cooling or inlet air cooling for gas peaking generation) hold promise, and may prove to be economic. Arrangements that give the grid operator control over loads for a contractual consideration or rate reduction will be more attractive as penetration of intermittent renewables increases.

*Pumped Storage Hydro*. Use of pumped storage hydro (PSH ) facilities was shown to increase for the scenarios examined. The infrastructure and policy necessary to allow optimal use of existing PSH within California should be enhanced. Additional PSH capability could also enhance system scheduling flexibility, and will likely aid other flexibility attributes discussed below. This is particularly true when conventional hydro flexibility is low, due to unusually high run-off conditions (Section 4.4.4).

*Hourly Schedule Flexibility.* The California grid should target a combination of in-state generating resources that provide a minimum level of scheduling flexibility. The anticipated load growth to 2020 will drive the overall system flexibility needs from the present level of about 4,300 MW/hr to about 6,000 MW/hr. The additional variability and uncertainty associated with intermittent renewables will increase the amplitude of sustained load ramps (both up and down), and the frequency of generation starts and stops. For the expected renewables growth trajectory (2010T, 2020), the overall hourly flexibility requirement is expected to be about 130 MW/hr greater than that required for load alone. Under the artificially accelerated renewable expansion of the 2010X scenario, that incremental requirement is about 400 MW/hr (Section 6.2.1).

During light load conditions, total requirements are smaller but the relative impact of intermittent renewables is larger. The anticipated load growth to 2020 will drive the light load system flexibility needs from the present level of about 2,000 MW/hr up to about 3,000 MW/hr. For the expected renewables growth trajectory (2010T, 2020), the hourly light load flexibility requirement is expected to be about 1,000 MW/hr greater than that required for load alone (Section 6.2.2).

*Hydro Scheduling*. Conventional hydroelectric generation plays a key role in light load schedule flexibility as well as load following and regulation. Economic operation will be enhanced by high hydro flexibility. Existing flexibility should be maintained at least, and investments to increase maneuverability should be considered. A documented inventory of capability is important. California should periodically examine the amount and type of hydro constraints, and evaluate investments or contractual mechanisms for cost-effective relief of those constraints (Sections 4.4.1, 4.4.4).

*Faster Start/Stop.* Uncertainties in forecasts create a somewhat different flexibility requirement. Even with state-of-the-art wind forecasting, both day-ahead and hour-ahead net load forecast uncertainties will increase due to intermittent renewables. With an increased risk of an actual net load significantly different from the forecast net load, short-notice start/stop capability during daily operation will be an important part of the redispatch needed to balance generation and load. The California grid should target sufficient in-state generating resource capability to meet day-ahead forecast errors in the range of ±5,000 MW, and hour-ahead forecast errors in the range of ±2,000 MW. Overall, this represents about double the present level of day-ahead load forecast error, and about 20 percent more than the present hour-ahead load forecast error (Sections 3.5, 6.3.1).

During lighter load periods, the net load forecast error may be three times the load alone forecast error in the day-ahead forecast. The targets recommended above will also be sufficient for light load conditions.

*Multi-Hour Schedule Flexibility.* Flexibility targets should also address periods of sustained load increases and decreases. The recommended targets are for the California grid to have resources adequate to meet a maximum morning load increase of 12,000 MW over three hours, and a maximum evening load decrease of 14,000 MW over three hours. This represents an increase of about 1,000 MW over the capability needed to meet the load alone (Sections 3.2.2, 6.3.1).

*Load Following Capability*. The California grid should target a combination of in-state generating resources that provide a minimum level of generation ramping capability, both up and down. On average, the system should maintain on the order of +/-130 MW/min for a minimum of 5 minutes. This is about a 10 MW/minute increase over the requirement due to load alone (Sections 3.4, 6.2.1, 6.3.3).

During light load conditions, approximately 70 MW/min of down load-following capability are required. Up load-following requirements are lower. The load-following capability should be subject to economic dispatch from the system operators. Load following duty should not be shifted to units providing regulation.

*Import/Export Scheduling*. The California grid should recognize that economic incorporation of substantial in-state renewables will inevitably involve significant displacement of imported energy. Regulatory and contractual arrangements for imports and exports should be structured such that the value of scheduling flexibility is recognized, allowed and appropriately compensated. In particular, California should allow schedule changes to occur more frequently and at times other than on the hour (Section 6.1).

*Regulation Capability*. The California grid should target a combination of in-state generating resources that provide a minimum level of regulation capability. The ISO currently procures regulation in the range of 300 MW to 600 MW. The procured amount varies substantially over all load levels. The impact of intermittent renewables on regulation (20 MW) is considerably less than the normal variability in the amount procured. However, regulation resources will continue to be important. Therefore, the California grid should at least maintain the current level of regulation capability. This level of regulation should allow the state to continue to satisfy their regulatory obligations for interchange and frequency control, i.e. NERC CPS2 performance. CPS2 performance should be continually scrutinized as intermittent renewables are added to the grid to refine regulation requirements and procurement (Sections 6.1, 3.4, 6.3.4).

*Regulation Technologies*. California should consider the use of technologies beyond conventional generation to provide regulation. The earlier discussion about load participation in schedule flexibility applies here as well. Functional requirements for loads to provide regulation are different from those for generation. Given a suitable regulatory and market structure, however, it is likely that other technologies and participants will emerge to provide the required services. Examples include some types of storage technology, such as variable speed pumped hydro and the latest flywheel energy storage systems. Policy and market structure should encourage diversity of participants in providing ancillary services, and technical specifications for performance should be sufficiently flexible to allow the introduction of new technologies.

*Non-Technical Resource Adequacy Considerations.* The preceding recommendations were aimed at securing the technical capabilities necessary for successful integration of intermittent renewables. The following items address policy and commercial considerations.

*Market Design.* It must be recognized that while operational flexibility is of considerable value to the grid, it currently holds little attraction for power suppliers. Deeper turnback, more rapid cycling and load following, and more frequent starts and stops all impose significant costs and revenue reductions on the suppliers. Market and regulatory structures must recognize the value of these flexibility features. Policy changes may include a combination of expanded ancillary services markets, incentives, and mandates.

*Contractual Obligations.* Much of the analysis presented in this report is based on the presumption that the grid is operated in a rational fashion – that is, the available generation resources are used as efficiently and economically as possible. The analysis did not include historical constraints (i.e. long term contractual obligations) that force the system to run less efficiently than possible. New contracts under consideration, existing long-term contracts up for renewal, or indeed any existing contracts that could be renegotiated should be reviewed with all of the preceding resource adequacy recommendations in mind. The California grid must maintain operational flexibility, and to do so, it must have not only the physical resources necessary, but also the business and contractual arrangements necessary to enable the rational use of those physical resources.

*Retirements.* Generating plant retirements that were firmly scheduled when the databases were assembled were incorporated into this study. However, increased competition from new resources, renewable or otherwise, will tend to push marginally profitable generating resources out of business. Such speculative, economic retirements were not considered in the study. Successful implementation of the recommendations above will ensure that resources with the necessary flexibility are available. In addition, it is recommended that retirements be projected, monitored, and evaluated during the resource planning process.

*Inventory.* During this study, it was noted that generator characteristics and capabilities (e.g., minimum turn down, ramp rate capability) were not always known with sufficient detail or certainty. Some degree of uncertainty is inevitable. However, with the increased need for resource flexibility, California should implement a program to measure, verify, and catalogue the flexibility characteristics of the generation resources. A program similar to the WECC generator dynamic testing might prove suitable.

### 7.3.2. Transmission Infrastructure

The addition of thousands of MW of new generation of any variety will require expansion of the transmission system. This study included the addition of sufficient bulk transmission necessary for connection of the new renewables to the grid as determined and documented by DPC [6]. However it was not a detailed transmission study and is not a substitute for one. Policymakers must recognize that local problems might develop, and enable the necessary transmission additions. Practice and policy that correct problems and strike a balance between infrastructure investment and congestion are necessary. To an appreciable extent, this observation holds for all transmission planning and all generation additions. California can economically benefit from changes in planning and operation of the transmission infrastructure by recognizing the locational and variable nature of intermittent renewables. The following are recommendations that are specific to these needs (Section 4.6).

*Existing Constraints.* California has existing infrastructure that contributes substantially to the secure and economic operation of the grid with high levels of intermittent renewables. In some circumstances, the use of that infrastructure for system-wide benefit is constrained by local transmission limitations. One example of such a constraint is the occasional inability of Helms pumped storage hydro to reach full pumping power (Section 4.4.4). Planning and policy should recognize and enable correction of such local limitations.

*Rating Criteria.* Wind generation is variable and the spatial diversity between multiple plants substantially impacts the coincident production of power from those plants. Clearly, an individual wind plant will reach rated output for many hours per year. Thus, normal planning criteria requires sufficient capability (i.e., thermal rating) on the transmission interconnection dedicated to that plant to accommodate rated power output.

However, as more wind plants vie for access to specific transmission corridors, it will be progressively less likely that all wind plants will simultaneously reach their maximum output. Note that in three years of data, all wind plants in this study *never* simultaneously reached maximum output. And, the 12,500 MW of wind generation exceeded 10,000 MW of production less than 1% of the time. Thus, transmission planning to accommodate multiple wind plants should consider their spatial diversity and the statistical expectation of simultaneous high power output levels. Plants in close proximity will generally require transmission capability equivalent to the aggregate rating of the plants. Plants that are farther apart may require less transmission capability. Hence, it is not necessary to guarantee sufficient rating on the bulk transmission infrastructure to accommodate all wind projects at full output. Existing criteria should be sufficient to provide this planning flexibility.

*Technology.* Policy should reward investment in technology to maximize use of transmission infrastructure for renewables. Such policies should recognize that wind generation is a relatively poor resource for capacity and that creative use of technology may optimize use of transmission. Regulatory and contractual practice should allow technologies such as real-time line ratings, controls that manage output from multiple intermittent renewable resources, local short-term forecasting, and other non-standard approaches to balance renewable energy delivery with transmission infrastructure costs.

### 7.3.3. Renewable Generation Technology, Policy, and Practice

With significant levels of intermittent renewable generation, operation may be challenging at extremely light load levels, under a constrained transmission grid, or with high wind volatility. Under these conditions, renewable generation must participate in overall grid control. The following recommendations are specific to renewable technology, and are aimed at assuring that intermittent renewables play an active and positive role in the secure and economic operation of the grid.

*Curtailment.* Under the rare occasions of coincident minimum load, high wind generation and low conventional hydro flexibility, it must be possible to curtail intermittent renewables. The grid operator should have the ability to order such a reduction in production. Regulatory and contractual arrangements for intermittent renewables should be structured such that curtailments are recognized, allowed and appropriately compensated. Ramp rate controls could also be considered (Section 5.2.2).

*Ancillary Services.* Intermittent renewables may be able to provide ancillary services that are both valuable and economic under some operating conditions. For example, wind generation can provide frequency regulation. Such functionality is a requirement in some regions [10]. Regulatory and contractual arrangements for intermittent renewables should be structured such that providing such services are recognized, allowed and appropriately compensated.

*Forecasting*. Successful and economic operation of the California grid requires wind and solar forecasting. This study verified substantial benefits from the use of state-of-the-art day-ahead forecasting in the unit commitment process. Substantial benefits are expected for improvements in both longer term (multi-day) and short-term (hours and minutes ahead) forecasting. Investment and policy must encourage development of high fidelity intermittent renewable forecasting for all intermittent renewable generation in the state (Sections 4.3, 6.3.1).

*Monitoring*. The wind production profiles used in this study are based on historical weather data and sophisticated computer models. Recorded data from real operating experience will be invaluable in refining operating practice, performance and flexibility requirements. Time synchronized production and meteorological data from many plants will provide validation or correction of the trends and results predicted by this study. They will show the benefits and limitations of spatial diversity, meso-scale modeling, and various wind plant controls. It is recommended that California continue and expand, as necessary, programs to monitor, analyze and disseminate performance information relevant to grid operations and planning for intermittent renewables.

## 7.4. Closure

The targeted levels of renewable generation can be successfully integrated into the California grid provided appropriate infrastructure, technology, and policies are in place.

# 8.0 References


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# Glossary

| | |
|---|---|
| ACE | Area control error |
| AGC | Automated generator control |
| AMWCO | aggregate megawatt contingency overload |
| ATC | Available transfer capability |
| CABPS | California Bulk Power Storage |
| California ISO | California Independent System Operator |
| CERTS | Consortium for Electric Reliability Technology Solutions |
| COI | California Oregon Intertie |
| $CO_2$ | Carbon dioxide |
| CPS2 | Control Performance Standard 2 |
| CPUC | California Public Utilities Commission |
| CS | Concentrating solar |
| CSP | concentrated solar power |
| CWEC | California Wind Energy Collaborative |
| DPC | Davis Power Consultants |
| DWR | Department of Water and Power |
| EAO | Electricity Analysis Office |
| Energy Commission | California Energy Commission |
| FERC | Federal Energy Regulatory Commission |
| GE | General Electric Energy Consulting |
| GE-MAPS™ | General Electric's Multi-Area Production Simulation |
| GW | gigawatt |
| IAP | Intermittency Analysis Project |
| ICAP | installed capacity |
| IEPR | Integrated Energy Policy Report |
| IID | Imperial Irrigation District |

| | |
|---|---|
| kV | kilovolt |
| LADWP | Los Angeles Department of Water and Power |
| LCOE | Levelized cost of energy |
| LVRT | Low voltage ride through |
| m/s | meters per second |
| MVA | megavolt amperes |
| MVAR | megavolt-amperes reactive |
| MW | megawatt |
| NERC | North American Electric Reliability Council |
| $NO_x$ | oxides of nitrogen |
| NREL | National Renewable Energy Laboratory |
| OASIS | Open Access Same-Time Information System |
| PG&E | Pacific Gas and Electric Company |
| PIER | Public Interest Energy Research |
| PSH | Pumped storage hydro |
| PSLF | Positive Sequence Load Flow |
| PSS | power system stabilizer |
| PV | photovoltaic |
| QSS | quasi-steady-state |
| RA | rolling average |
| RAS | Remedial action schemes |
| RD&D | research, development and demonstration |
| RPS | Renewables Portfolio Standard |
| RTBR | Renewable Transmission Benefit Ratio |
| SCE | Southern California Edison Company |
| SDG&E | San Diego Gas and Electric Company |
| SGIP | Self Generation Incentive Program |
| SMUD | Sacramento Municipal Utility District |

| | |
|---|---|
| $SO_x$ | oxides of sulfur |
| SVA | Strategic Value Analysis |
| UCAP | uniform capacity |
| VAR | voltage-ampere reactive |
| V-Reg | voltage regulation |
| WECC | Western Electricity Coordinating Council |
| $w/m^2$ | watts per square meter |
| WTRL | Weighted Transmission Loading Relief factor |

# Appendix A. Summary of Wind Projects by Scenario

The wind projects included in each study scenario are shown in the following tables. Each table identifies a project by its power flow bus number, bus name, and voltage level in the first three columns. The fourth column shows the rated power output for an individual project, and the final column shows the site number from the AWS wind profile data.

Table 41 lists the wind projects included in the 2006 study scenario. Table 42 lists the incremental projects added to the 2006 scenario to create the 2010T scenario. Table 43 lists the incremental projects added to the 2010T scenario to create the 2010X scenario. Table 44 lists the incremental projects added to the 2010X scenario to create the 2020 scenario.

**Table 41. Wind Projects Included in 2006 Study Scenario.**

| Power Flow Data | | | | |
|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Total MW Rating** | **AWS Site #** |
| 24009 | APPGEN1G | 13.8 | 55 | 14 |
| 24010 | APPGEN2G | 13.8 | 55 | 7 |
| 24136 | SEAWEST | 230 | 263 | 1 |
| 24152 | VESTAL | 66 | 8 | 3 |
| 24152 | VESTAL | 66 | 50 | 8 |
| 24422 | PALMDALE | 66 | 1 | 6 |
| 24436 | GOLDTOWN | 66 | 13 | 2 |
| 24457 | ARBWIND | 66 | 22 | 9 |
| 24458 | ENCANWND | 66 | 113 | 4 |
| 24459 | FLOWIND | 66 | 41 | 34 |
| 24460 | DUTCHWND | 66 | 14 | 5 |
| 24465 | MORWIND | 66 | 56 | 32 |
| 24826 | INDIGO | 115 | 21 | 23 |
| 24914 | MTNVIEW1 | 13.8 | 63 | 29 |
| 24915 | MTNVIEW2 | 13.8 | 63 | 30 |
| 25632 | TERAWND | 115 | 23 | 22 |
| 25633 | CAPWIND | 115 | 20 | 18 |
| 25634 | BUCKWND | 115 | 21 | 20 |
| 25635 | ALTWIND | 115 | 50 | 17 |
| 25636 | RENWIND | 115 | 13 | 31 |
| 25637 | TRANWND | 115 | 60 | 27 |
| 25639 | SEAWIND | 115 | 27 | 21 |
| 25640 | PANAERO | 115 | 30 | 28 |
| 25645 | VENWIND | 115 | 45 | 16 |
| 25646 | SANWIND | 115 | 28 | 19 |
| 28501 | MIDWIND | 12 | 18 | 13 |
| 28502 | SOUTHWND | 12 | 35 | 10 |
| 28503 | NORTHWND | 12 | 19 | 12 |
| 28504 | ZONDWND1 | 12 | 26 | 15 |
| 28506 | BREEZE1 | 12 | 13 | 11 |
| 32168 | USWINDPW | 9.11 | 50 | 25 |

**Table 41 (continued). Wind Projects Included in 2006 Study Scenario.**

| Power Flow Data | | | | |
|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Total MW Rating** | **AWS Site #** |
| 32172 | HIGHWNDS | 34.5 | 160 | 24 |
| 33170 | WINDMSTR | 9.11 | 38 | 37 |
| 33171 | TRSVQ+NW | 9.11 | 28 | 38 |
| 33175 | ALTAMONT | 9.11 | 13 | 39 |
| 33175 | ALTAMONT | 9.11 | 16 | 40 |
| 33834 | KALINA | 9.11 | 7 | 41 |
| 33836 | USWP_#4 | 9.11 | 24 | 42 |
| 33836 | USWP_#4 | 9.11 | 41 | 43 |
| 33836 | USWP_#4 | 9.11 | 17 | 44 |
| 33838 | USWP_#3 | 9.11 | 77 | 45 |
| 33840 | FLOWD3-6 | 9.11 | 19 | 26 |
| 33840 | FLOWD3-6 | 9.11 | 19 | 46 |
| 33840 | FLOWD3-6 | 9.11 | 19 | 47 |
| 33840 | FLOWD3-6 | 9.11 | 19 | 48 |
| 33842 | PATTERSN | 9.11 | 2 | 50 |
| 33842 | PATTERSN | 9.11 | 30 | 51 |
| 33842 | PATTERSN | 9.11 | 70 | 52 |
| 34342 | INT.TURB | 9.11 | 13 | 33 |
| 35310 | LFC FIN+ | 9.11 | 22 | 35 |
| 35312 | SEAWESTF | 9.11 | 13 | 36 |
| 35314 | WALKER+ | 9.11 | 100 | 53 |
| 35316 | ZOND SYS | 9.11 | 20 | 54 |
| 35318 | FLOWDPTR | 9.11 | 9 | 55 |
| 35320 | USW FRIC | 12 | 10 | 56 |
| 35320 | USW FRIC | 12 | 5 | 57 |

**Table 42. Incremental Wind Projects Added for 2010T Study Scenario.**

| Power Flow Data | | | | |
|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Added MW Rating** | **AWS Site #** |
| 24056 | ETIWANDA | 230 | 168 | 59 |
| 24520 | TEHACHPI | 500 | 500 | 61 |
| 24520 | TEHACHPI | 500 | 500 | 62 |
| 24520 | TEHACHPI | 500 | 105 | 82 |
| 24520 | TEHACHPI | 500 | 100 | 83 |
| 24520 | TEHACHPI | 500 | 108 | 84 |
| 24520 | TEHACHPI | 500 | 100 | 85 |
| 24520 | TEHACHPI | 500 | 150 | 86 |
| 24520 | TEHACHPI | 500 | 110 | 87 |
| 24520 | TEHACHPI | 500 | 105 | 88 |
| 24520 | TEHACHPI | 500 | 101 | 89 |
| 24520 | TEHACHPI | 500 | 100 | 90 |
| 24520 | TEHACHPI | 500 | 100 | 91 |

**Table 42 (continued). Incremental Wind Projects added for 2010T Study Scenario.**

| Power Flow Data | | | | |
|---|---|---|---|---|
| Bus # | Bus Name | kV | Added MW Rating | AWS Site # |
| 24520 | TEHACHPI | 500 | 102 | 92 |
| 24520 | TEHACHPI | 500 | 103 | 93 |
| 24520 | TEHACHPI | 500 | 112 | 94 |
| 24520 | TEHACHPI | 500 | 103 | 95 |
| 24520 | TEHACHPI | 500 | 142 | 96 |
| 24520 | TEHACHPI | 500 | 103 | 97 |
| 24520 | TEHACHPI | 500 | 100 | 98 |
| 24520 | TEHACHPI | 500 | 183 | 99 |
| 24815 | GARNET | 115 | 21 | 76 |
| 24828 | WINTEC9 | 13.8 | 61 | 77 |
| 25632 | TERAWND | 115 | 158 | 63 |
| 25633 | CAPWIND | 115 | 158 | 64 |
| 25634 | BUCKWND | 115 | 158 | 65 |
| 25635 | ALTWIND | 115 | 154 | 66 |
| 25636 | RENWIND | 115 | 158 | 67 |
| 25637 | TRANWND | 115 | 158 | 68 |
| 25639 | SEAWIND | 115 | 158 | 69 |
| 25645 | VENWIND | 115 | 154 | 70 |
| 25646 | SANWIND | 115 | 156 | 71 |
| 25902 | NEWSD138 | 138 | 90 | 58 |
| 26135 | WTG | 0.57 | 120 | 75 |
| 26160 | LA-Wind | 230 | 120 | 74 |
| 28020 | WINTEC6 | 115 | 38 | 78 |
| 28060 | SEAWEST | 115 | 76 | 79 |
| 28061 | WHITEWTR | 33 | 66 | 80 |
| 28280 | CABAZON | 33 | 43 | 81 |
| 30529 | HIWD TAP | 230 | 165 | 72 |
| 38610 | DELTAPMP | 230 | 80 | 73 |

**Table 43. Incremental Wind Projects Added for 2010X Study Scenario.**

| Power Flow Data | | | | |
|---|---|---|---|---|
| Bus # | Bus Name | kV | Added MW Rating | AWS Site # |
| 21915 | IMPERHWD | 500 | 110 | 106 |
| 21915 | IMPERHWD | 500 | 110 | 136 |
| 21915 | IMPERHWD | 500 | 111 | 138 |
| 21915 | IMPERHWD | 500 | 131 | 158 |
| 21915 | IMPERHWD | 500 | 138 | 189 |
| 22465 | SDGEHWD | 500 | 110 | 165 |
| 22465 | SDGEHWD | 500 | 110 | 176 |
| 22465 | SDGEHWD | 500 | 125 | 199 |
| 22465 | SDGEHWD | 500 | 155 | 220 |
| 24056 | ETIWANDA | 230 | 100 | 105 |

**Table 43 (continued). Incremental Wind Projects Added for 2010X Study Scenario.**

| Power Flow Data | | | | |
|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Added MW Rating** | **AWS Site #** |
| 24056 | ETIWANDA | 230 | 104 | 110 |
| 24056 | ETIWANDA | 230 | 100 | 112 |
| 24056 | ETIWANDA | 230 | 102 | 124 |
| 24056 | ETIWANDA | 230 | 71 | 128 |
| 24520 | TEHACHPI | 500 | 104 | 113 |
| 24520 | TEHACHPI | 500 | 145 | 116 |
| 24520 | TEHACHPI | 500 | 106 | 119 |
| 24520 | TEHACHPI | 500 | 113 | 121 |
| 24520 | TEHACHPI | 500 | 158 | 125 |
| 24520 | TEHACHPI | 500 | 100 | 126 |
| 24520 | TEHACHPI | 500 | 124 | 127 |
| 24520 | TEHACHPI | 500 | 132 | 130 |
| 24520 | TEHACHPI | 500 | 105 | 131 |
| 24520 | TEHACHPI | 500 | 125 | 134 |
| 24520 | TEHACHPI | 500 | 101 | 146 |
| 24520 | TEHACHPI | 500 | 100 | 147 |
| 24520 | TEHACHPI | 500 | 92 | 148 |
| 26160 | LA-Wind | 230 | 80 | 153 |
| 30105 | COTWD_E | 230 | 134 | 108 |
| 30529 | HIWD TAP | 230 | 103 | 100 |
| 30529 | HIWD TAP | 230 | 102 | 102 |
| 30529 | HIWD TAP | 230 | 114 | 103 |
| 30529 | HIWD TAP | 230 | 117 | 104 |
| 30529 | HIWD TAP | 230 | 107 | 107 |
| 30529 | HIWD TAP | 230 | 107 | 109 |
| 30529 | HIWD TAP | 230 | 114 | 111 |
| 30529 | HIWD TAP | 230 | 152 | 114 |
| 31665 | WESTWOOD | 230 | 104 | 122 |
| 31665 | WESTWOOD | 230 | 100 | 133 |
| 31665 | WESTWOOD | 230 | 100 | 137 |
| 31665 | WESTWOOD | 230 | 100 | 157 |
| 31665 | WESTWOOD | 230 | 114 | 166 |
| 31665 | WESTWOOD | 230 | 131 | 232 |
| 34342 | INT.TURB | 9.11 | 40 | 172 |
| 38610 | DELTAPMP | 230 | 40 | 73 |

**Table 44. Incremental Wind Projects Added for 2020 Study Scenario.**

| Power Flow Data | | | | |
|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Added MW Rating** | **AWS Site #** |
| 24098 | MOORPARK | 66 | 50 | 161 |
| 25903 | INYOWIND | 115 | 100 | 162 |
| 33170 | WINDMSTR | 9.11 | 28 | 37 |
| 38610 | DELTAPMP | 230 | 80 | 73 |

# Appendix B. Summary of Solar Projects by Scenario

The solar projects included in each study scenario are shown in the following tables. Each table identifies a project by its power flow bus number, bus name, and voltage level in the first three columns. The fourth column shows the rated power output for an individual project and the fifth column shows the project type (i.e., concentrated or photo-voltaic). The final column shows the type of profile used in the sub-hourly statistical and QSS analyses.

Table 45 lists the concentrated solar projects included in the 2006 study scenario. All 2006 PV sites were incorporated into the load, and not represented individually. Table 46 lists the incremental projects added to the 2006 scenario to create the 2010T scenario. Table 47 lists the incremental projects added to the 2010T scenario to create the 2010X scenario. Table 48 lists the incremental projects added to the 2010X scenario to create the 2020 scenario.

**Table 45. Solar Projects Included in 2006 Study Scenario.**

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Total MW Rating** | **Project Type** | **Profile Type** |
| 24737 | LUZ8 G | 13.8 | 80 | Concentrated | Sungen/Luz |
| 24738 | LUZ9 G | 13.8 | 80 | Concentrated | Sungen/Luz |
| 24754 | SUNGEN3G | 13.8 | 34 | Concentrated | Sungen/Luz |
| 24755 | SUNGEN4G | 13.8 | 34 | Concentrated | Sungen/Luz |
| 24756 | SUNGEN5G | 13.8 | 34 | Concentrated | Sungen/Luz |
| 24757 | SUNGEN6G | 13.8 | 35 | Concentrated | Sungen/Luz |
| 24758 | SUNGEN7G | 13.8 | 35 | Concentrated | Sungen/Luz |

**Table 46. Incremental Solar Projects Added for 2010T Study Scenario.**

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Added MW Rating** | **Project Type** | **Profile Type** |
| 21032 | EMESA1 | 92 | 11 | Concentrated | Sungen/Luz |
| 21033 | EMESA2 | 92 | 11 | Concentrated | Sungen/Luz |
| 21038 | HIGHLINE | 230 | 11 | Concentrated | Sungen/Luz |
| 21039 | HIGHLINE | 92 | 11 | Concentrated | Sungen/Luz |
| 21043 | LEATHERS | 92 | 11 | Concentrated | Sungen/Luz |
| 21045 | MIDWAY X | 230 | 11 | Concentrated | Sungen/Luz |
| 22068 | BOLDRCRK | 69 | 7 | Concentrated | Sungen/Luz |
| 22360 | IMPRLVLY | 500 | 300 | Concentrated | Stirling |
| 24097 | MOHAVE | 500 | 500 | Concentrated | Stirling |
| 24751 | SEGS 1G | 14 | 20 | Concentrated | Sungen/Luz |
| 24752 | SEGS 2G | 14 | 32.6 | Concentrated | Sungen/Luz |
| 24902 | VSTA | 66 | 50 | Concentrated | Sungen/Luz |
| 31678 | GRYS FLT | 60 | 23 | Concentrated | Sungen/Luz |
| 21004 | AVE58 | 92 | 3 | PV | Zip Code 920 |
| 22008 | ASH | 69 | 2 | PV | Zip Code 920 |
| 22048 | BATIQTOS | 138 | 2 | PV | Zip Code 920 |
| 22056 | BERNARDO | 69 | 3 | PV | Zip Code 921 |
| 22108 | CANNON | 138 | 2 | PV | Zip Code 920 |

**Table 46 (continued). Incremental Solar Projects Added for 2010T Study Scenario.**

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| Bus # | Bus Name | kV | Added MW Rating | Project Type | Profile Type |
| 22112 | CAPSTRNO | 138 | 4 | PV | Zip Code 920 |
| 22124 | CHCARITA | 138 | 2 | PV | Zip Code 920 |
| 22160 | DEL MAR | 69 | 2 | PV | Zip Code 920 |
| 22208 | EL CAJON | 69 | 2 | PV | Zip Code 920 |
| 22216 | ELLIOTT | 69 | 2 | PV | Zip Code 921 |
| 22252 | ENCNITAS | 69 | 2 | PV | Zip Code 920 |
| 22256 | ESCNDIDO | 69 | 2 | PV | Zip Code 920 |
| 22272 | ESCO | 69 | 2 | PV | Zip Code 920 |
| 22288 | FELICITA | 69 | 2 | PV | Zip Code 920 |
| 22316 | GENESEE | 69 | 3 | PV | Zip Code 921 |
| 22336 | GRANITE | 69 | 2 | PV | Zip Code 920 |
| 22364 | JAMACHA | 69 | 2 | PV | Zip Code 920 |
| 22372 | KEARNY | 69 | 2 | PV | Zip Code 921 |
| 22396 | LAGNA NL | 138 | 9 | PV | Zip Code 920 |
| 22408 | LOSCOCHS | 69 | 2 | PV | Zip Code 921 |
| 22432 | MARGARTA | 138 | 15 | PV | Zip Code 920 |
| 22440 | MELROSE | 69 | 3 | PV | Zip Code 920 |
| 22444 | MESA RIM | 69 | 2 | PV | Zip Code 921 |
| 22448 | MESAHGTS | 69 | 2 | PV | Zip Code 921 |
| 22480 | MIRAMAR | 69 | 2 | PV | Zip Code 921 |
| 22496 | MISSION | 69 | 3 | PV | Zip Code 921 |
| 22516 | MONTGMRY | 69 | 2 | PV | Zip Code 921 |
| 22532 | MURRAY | 69 | 2 | PV | Zip Code 920 |
| 22592 | OLD TOWN | 69 | 2 | PV | Zip Code 921 |
| 22620 | PACFCBCH | 69 | 2 | PV | Zip Code 921 |
| 22632 | PALOMAR | 138 | 2 | PV | Zip Code 920 |
| 22656 | PICO | 138 | 4 | PV | Zip Code 920 |
| 22660 | POINTLMA | 69 | 2 | PV | Zip Code 921 |
| 22676 | R.CARMEL | 69 | 2 | PV | Zip Code 920 |
| 22704 | SAMPSON | 13 | 2 | PV | Zip Code 921 |
| 22708 | SANLUSRY | 69 | 2 | PV | Zip Code 920 |
| 22724 | SANMRCOS | 69 | 2 | PV | Zip Code 920 |
| 22760 | SHADOWR | 138 | 2 | PV | Zip Code 920 |
| 22800 | STREAMVW | 69 | 2 | PV | Zip Code 921 |
| 22852 | TELECYN | 138 | 2 | PV | Zip Code 921 |
| 22856 | TOREYPNS | 69 | 3 | PV | Zip Code 921 |
| 22868 | URBAN | 69 | 2 | PV | Zip Code 921 |
| 24024 | CHINO | 66 | 12 | PV | Zip Code 91A |
| 24055 | ETIWANDA | 66 | 8 | PV | Zip Code 91A |
| 24111 | PADUA | 66 | 12 | PV | Zip Code 91A |
| 24133 | SANTIAGO | 66 | 11 | PV | Zip Code 91A |
| 24135 | SAUGUS | 66 | 18 | PV | Zip Code 91A |

**Table 46 (continued). Incremental Solar Projects Added for 2010T Study Scenario.**

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Added MW Rating** | **Project Type** | **Profile Type** |
| 24157 | WALNUT | 66 | 10 | PV | Zip Code 91A |
| 24160 | VALLEYSC | 115 | 5 | PV | Zip Code 91A |
| 24205 | EAGLROCK | 66 | 3 | PV | Zip Code 91A |
| 24207 | JOHANNA | 66 | 6 | PV | Zip Code 91A |
| 24211 | OLINDA | 66 | 7 | PV | Zip Code 91A |
| 24216 | VILLA PK | 66 | 10 | PV | Zip Code 91A |
| 24418 | LANCSTR | 66 | 6 | PV | Zip Code 91A |
| 24422 | PALMDALE | 66 | 3 | PV | Zip Code 91A |
| 24424 | QUARTZHL | 66 | 5 | PV | Zip Code 91B |
| 24426 | SHUTTLE | 66 | 3 | PV | Zip Code 91B |
| 24602 | VICTOR | 115 | 6 | PV | Zip Code 91B |
| 24603 | APPLEVAL | 115 | 5 | PV | Zip Code 91B |
| 24605 | HESPERIA | 115 | 5 | PV | Zip Code 91B |
| 24608 | SAVAGE | 115 | 5 | PV | Zip Code 91B |
| 24816 | SANTA RO | 115 | 3 | PV | Zip Code 91B |
| 24817 | EISENHOW | 115 | 3 | PV | Zip Code 91B |
| 24821 | TAMARISK | 115 | 2 | PV | Zip Code 91B |
| 24822 | INDIAN W | 115 | 1 | PV | Zip Code 91B |
| 24902 | VSTA | 66 | 10 | PV | Zip Code 91B |
| 24903 | VSTA | 115 | 6 | PV | Zip Code 91B |
| 25002 | GOODRICH | 33 | 10 | PV | Zip Code 91B |
| 25202 | LEWIS | 66 | 8 | PV | Zip Code 91B |
| 26013 | GLENDAL | 230 | 3 | PV | Zip Code 900 |
| 26061 | RINALDI | 230 | 4 | PV | Zip Code 900 |
| 26063 | RIVER | 230 | 6 | PV | Zip Code 900 |
| 26068 | STJOHN | 230 | 3 | PV | Zip Code 900 |
| 26076 | FAIRFAX | 138 | 7 | PV | Zip Code 900 |
| 26078 | TOLUCA | 230 | 17 | PV | Zip Code 900 |
| 26081 | ATWATER | 230 | 5 | PV | Zip Code 905 |
| 26085 | HOLYWDLD | 138 | 7 | PV | Zip Code 905 |
| 26086 | NRTHRDGE | 230 | 9 | PV | Zip Code 905 |
| 26088 | OLYMPCLD | 138 | 7 | PV | Zip Code 905 |
| 26093 | TARZANA | 230 | 12 | PV | Zip Code 905 |
| 26102 | VALLEY | 138 | 4 | PV | Zip Code 905 |
| 30535 | TIDEWATR | 230 | 1 | PV | Zip Code 94A |
| 30545 | ROSSMOOR | 230 | 1 | PV | Zip Code 945 |
| 30555 | SANRAMON | 230 | 3 | PV | Zip Code 945 |
| 30561 | TASSAJAR | 230 | 1 | PV | Zip Code 945 |
| 30585 | LS PSTAS | 230 | 5 | PV | Zip Code 945 |
| 30720 | SARATOGA | 230 | 3 | PV | Zip Code 94A |
| 30730 | HICKS | 230 | 3 | PV | Zip Code 94A |
| 30841 | FIGRDN 1 | 230 | 2 | PV | Zip Code 95A |

**Table 46 (continued). Incremental Solar Projects Added for 2010T Study Scenario.**

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Added MW Rating** | **Project Type** | **Profile Type** |
| 30846 | FIGRDN 2 | 230 | 2 | PV | Zip Code 95A |
| 30850 | ASHLAN | 230 | 4 | PV | Zip Code 95A |
| 32971 | MEDW LNE | 115 | 1 | PV | Zip Code 945 |
| 32973 | LAKEWD-C | 115 | 1 | PV | Zip Code 945 |
| 32974 | LAKEWD-M | 115 | 1 | PV | Zip Code 945 |
| 33714 | HAMMER | 60 | 4 | PV | Zip Code 95A |
| 33801 | STAGG_5 | 21 | 4 | PV | Zip Code 95A |
| 33803 | STAGG_6 | 21 | 4 | PV | Zip Code 95A |
| 34372 | MALAGA | 115 | 2 | PV | Zip Code 95A |
| 34404 | WST FRSO | 115 | 2 | PV | Zip Code 95A |
| 34408 | BARTON | 115 | 3 | PV | Zip Code 95A |
| 34410 | MANCHSTR | 115 | 2 | PV | Zip Code 95A |
| 34414 | WOODWARD | 115 | 3 | PV | Zip Code 95A |
| 34416 | BULLARD | 115 | 3 | PV | Zip Code 95A |
| 34706 | WESTPARK | 115 | 4 | PV | Zip Code 95A |
| 34718 | KERN OIL | 115 | 4 | PV | Zip Code 95A |
| 34736 | MAGUNDEN | 115 | 4 | PV | Zip Code 95A |
| 35353 | MT VIEW | 115 | 2 | PV | Zip Code 94A |
| 35354 | STELLING | 115 | 2 | PV | Zip Code 94A |
| 35363 | LAWRENCE | 115 | 2 | PV | Zip Code 94A |
| 35368 | BRITTN | 115 | 2 | PV | Zip Code 94A |
| 35610 | MONTAGUE | 115 | 3 | PV | Zip Code 95A |
| 35612 | TRIMBLE | 115 | 3 | PV | Zip Code 95A |
| 35620 | EL PATIO | 115 | 3 | PV | Zip Code 95A |
| 35622 | SWIFT | 115 | 3 | PV | Zip Code 945 |
| 35624 | MILPITAS | 115 | 3 | PV | Zip Code 945 |
| 35626 | MCKEE | 115 | 2 | PV | Zip Code 95A |
| 35638 | EDENVALE | 115 | 3 | PV | Zip Code 95A |
| 35646 | MRGN HIL | 115 | 2 | PV | Zip Code 94A |
| 36850 | KIFER | 115 | 3 | PV | Zip Code 94A |
| 36852 | SCOTT | 115 | 3 | PV | Zip Code 94A |
| 37101 | CARMICAL | 69 | 7 | PV | Zip Code 956 |
| 37103 | ELVERTA1 | 69 | 3 | PV | Zip Code 956 |
| 37104 | ELVERTA2 | 69 | 4 | PV | Zip Code 956 |
| 37114 | ORANGVL1 | 69 | 7 | PV | Zip Code 956 |
| 37115 | ORANGVL2 | 69 | 7 | PV | Zip Code 956 |
| 37649 | LLNLAB | 115 | 4 | PV | Zip Code 945 |
| 38028 | PLO ALTO | 115 | 4 | PV | Zip Code 94A |
| 38280 | SYLVAN | 69 | 13 | PV | Zip Code 95A |

**Table 47. Incremental Solar Projects Added for 2010X Study Scenario.**

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| Bus # | Bus Name | kV | Added MW Rating | Project Type | Profile Type |
| 21032 | EMESA1 | 92 | 39 | Concentrated | Sungen/Luz |
| 21033 | EMESA2 | 92 | 39 | Concentrated | Sungen/Luz |
| 21038 | HIGHLINE | 230 | 39 | Concentrated | Sungen/Luz |
| 21045 | MIDWAY X | 230 | 39 | Concentrated | Sungen/Luz |
| 22068 | BOLDRCRK | 69 | 13 | Concentrated | Sungen/Luz |
| 31678 | GRYS FLT | 60 | -23 | Concentrated | Sungen/Luz |

**Table 48. Incremental Solar Projects Added for 2020 Study Scenario.**

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| Bus # | Bus Name | kV | Added MW Rating | Project Type | Profile Type |
| 21032 | EMESA1 | 92 | 30 | Concentrated | Sungen/Luz |
| 21033 | EMESA2 | 92 | 30 | Concentrated | Sungen/Luz |
| 21038 | HIGHLINE | 230 | 30 | Concentrated | Sungen/Luz |
| 21039 | HIGHLINE | 92 | 39 | Concentrated | Sungen/Luz |
| 21043 | LEATHERS | 92 | 69 | Concentrated | Sungen/Luz |
| 21045 | MIDWAY X | 230 | 30 | Concentrated | Sungen/Luz |
| 22360 | IMPRLVLY | 500 | 200 | Concentrated | Stirling |
| 24097 | MOHAVE | 500 | 350 | Concentrated | Stirling |
| 24809 | YUCCA | 115 | -14 | Concentrated | Sungen/Luz |
| 24810 | HI DESER | 115 | 18 | Concentrated | Sungen/Luz |
| 24817 | EISENHOW | 115 | -1 | Concentrated | Sungen/Luz |
| 24819 | CONCHO | 115 | -1 | Concentrated | Sungen/Luz |
| 24824 | CARODEAN | 115 | 18 | Concentrated | Sungen/Luz |
| 24902 | VSTA | 66 | -50 | Concentrated | Sungen/Luz |
| 24903 | VSTA | 66 | 18 | Concentrated | Sungen/Luz |
| 24909 | PEPPER | 115 | 23 | Concentrated | Sungen/Luz |
| 24911 | HOMART | 115 | 18 | Concentrated | Sungen/Luz |
| 24912 | SHANDIN | 115 | 18 | Concentrated | Sungen/Luz |
| 25602 | DVLCYN34 | 115 | 18 | Concentrated | Sungen/Luz |
| 25632 | TERAWND | 115 | -1 | Concentrated | Sungen/Luz |
| 25633 | CAPWIND | 115 | -1 | Concentrated | Sungen/Luz |
| 25635 | ALTWIND | 115 | -30 | Concentrated | Sungen/Luz |
| 25636 | RENWIND | 115 | 20 | Concentrated | Sungen/Luz |
| 25639 | SEAWIND | 115 | -30 | Concentrated | Sungen/Luz |
| 25645 | VENWIND | 115 | -1 | Concentrated | Sungen/Luz |
| 25646 | SANWIND | 115 | -1 | Concentrated | Sungen/Luz |
| 25650 | MHV SPHN | 115 | -17 | Concentrated | Sungen/Luz |
| 31678 | GRYS FLT | 60 | 23 | Concentrated | Sungen/Luz |
| 31665 | WESTWOOD | 230 | 200 | Concentrated | Sungen/Luz |
| 21002 | AVE42 | 92 | 19 | PV | Zip Code 920 |
| 21005 | COACHELA | 92 | 20 | PV | Zip Code 920 |
| 22008 | ASH | 69 | 8 | PV | Zip Code 920 |

**Table 48 (continued). Incremental Solar Projects Added for 2020 Study Scenario.**

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| Bus # | Bus Name | kV | Added MW Rating | Project Type | Profile Type |
| 22024 | B | 69 | 10 | PV | Zip Code 921 |
| 22048 | BATIQTOS | 138 | 8 | PV | Zip Code 920 |
| 22056 | BERNARDO | 69 | 7 | PV | Zip Code 921 |
| 22108 | CANNON | 138 | 8 | PV | Zip Code 920 |
| 22124 | CHCARITA | 138 | 5 | PV | Zip Code 920 |
| 22132 | CHOLLAS | 69 | 3 | PV | Zip Code 920 |
| 22160 | DEL MAR | 69 | 1 | PV | Zip Code 920 |
| 22208 | EL CAJON | 69 | 8 | PV | Zip Code 920 |
| 22216 | ELLIOTT | 69 | 1 | PV | Zip Code 921 |
| 22252 | ENCNITAS | 69 | 5 | PV | Zip Code 920 |
| 22256 | ESCNDIDO | 69 | 13 | PV | Zip Code 920 |
| 22276 | F | 69 | 7 | PV | Zip Code 921 |
| 22316 | GENESEE | 69 | 7 | PV | Zip Code 921 |
| 22336 | GRANITE | 69 | 8 | PV | Zip Code 920 |
| 22364 | JAMACHA | 69 | 8 | PV | Zip Code 920 |
| 22372 | KEARNY | 69 | 8 | PV | Zip Code 921 |
| 22396 | LAGNA NL | 138 | 11 | PV | Zip Code 920 |
| 22408 | LOSCOCHS | 69 | 5 | PV | Zip Code 921 |
| 22432 | MARGARTA | 138 | 37 | PV | Zip Code 920 |
| 22440 | MELROSE | 69 | 14 | PV | Zip Code 920 |
| 22444 | MESA RIM | 69 | 8 | PV | Zip Code 921 |
| 22448 | MESAHGTS | 69 | 3 | PV | Zip Code 921 |
| 22480 | MIRAMAR | 69 | 8 | PV | Zip Code 921 |
| 22496 | MISSION | 69 | 7 | PV | Zip Code 921 |
| 22516 | MONTGMRY | 69 | 1 | PV | Zip Code 921 |
| 22532 | MURRAY | 69 | 8 | PV | Zip Code 920 |
| 22576 | NOISLMTR | 69 | 7 | PV | Zip Code 921 |
| 22580 | NORTHCTY | 138 | 3 | PV | Zip Code 920 |
| 22592 | OLD TOWN | 69 | 8 | PV | Zip Code 921 |
| 22620 | PACFCBCH | 69 | 1 | PV | Zip Code 921 |
| 22636 | PARADISE | 69 | 3 | PV | Zip Code 921 |
| 22656 | PICO | 138 | 6 | PV | Zip Code 920 |
| 22660 | POINTLMA | 69 | 1 | PV | Zip Code 921 |
| 22664 | POMERADO | 69 | 3 | PV | Zip Code 920 |
| 22668 | POWAY | 69 | 3 | PV | Zip Code 920 |
| 22676 | R.CARMEL | 69 | 1 | PV | Zip Code 920 |
| 22696 | ROSE CYN | 69 | 7 | PV | Zip Code 921 |
| 22704 | SAMPSON | 12.5 | 8 | PV | Zip Code 921 |
| 22708 | SANLUSRY | 69 | 13 | PV | Zip Code 920 |
| 22724 | SANMRCOS | 69 | 8 | PV | Zip Code 920 |
| 22734 | SANTEE | 138 | 7 | PV | Zip Code 920 |
| 22760 | SHADOWR | 138 | 8 | PV | Zip Code 920 |

**Table 48 (continued). Incremental Solar Projects Added for 2020 Study Scenario.**

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Added MW Rating** | **Project Type** | **Profile Type** |
| 22800 | STREAMVW | 69 | 5 | PV | Zip Code 921 |
| 22820 | SWEETWTR | 69 | 3 | PV | Zip Code 921 |
| 22852 | TELECYN | 138 | 5 | PV | Zip Code 921 |
| 22856 | TOREYPNS | 69 | 7 | PV | Zip Code 921 |
| 22868 | URBAN | 69 | 5 | PV | Zip Code 921 |
| 24007 | ALMITOSW | 66 | 10 | PV | Zip Code 91A |
| 24024 | CHINO | 66 | 59 | PV | Zip Code 91A |
| 24028 | DELAMO | 66 | 10 | PV | Zip Code 91A |
| 24032 | AMERON | 66 | 13 | PV | Zip Code 91A |
| 24039 | EL NIDO | 66 | 27 | PV | Zip Code 91A |
| 24055 | ETIWANDA | 66 | 32 | PV | Zip Code 91A |
| 24083 | LITEHIPE | 66 | 15 | PV | Zip Code 91A |
| 24111 | PADUA | 66 | 38 | PV | Zip Code 91A |
| 24133 | SANTIAGO | 66 | 30 | PV | Zip Code 91A |
| 24135 | SAUGUS | 66 | 63 | PV | Zip Code 91A |
| 24157 | WALNUT | 66 | 40 | PV | Zip Code 91A |
| 24160 | VALLEYSC | 115 | 25 | PV | Zip Code 91A |
| 24201 | BARRE | 66 | 21 | PV | Zip Code 91A |
| 24205 | EAGLROCK | 66 | 22 | PV | Zip Code 91A |
| 24207 | JOHANNA | 66 | 14 | PV | Zip Code 91A |
| 24211 | OLINDA | 66 | 18 | PV | Zip Code 91A |
| 24212 | RECTOR | 66 | 28 | PV | Zip Code 91A |
| 24213 | RIOHONDO | 66 | 29 | PV | Zip Code 91A |
| 24216 | VILLA PK | 66 | 11 | PV | Zip Code 91A |
| 24407 | ANAVERDE | 66 | 10 | PV | Zip Code 91A |
| 24418 | LANCSTR | 66 | 24 | PV | Zip Code 91A |
| 24421 | OASIS SC | 66 | 10 | PV | Zip Code 91A |
| 24422 | PALMDALE | 66 | 12 | PV | Zip Code 91A |
| 24424 | QUARTZHL | 66 | 13 | PV | Zip Code 91B |
| 24426 | SHUTTLE | 66 | 12 | PV | Zip Code 91B |
| 24602 | VICTOR | 115 | 7 | PV | Zip Code 91B |
| 24603 | APPLEVAL | 115 | 5 | PV | Zip Code 91B |
| 24604 | AQUEDUCT | 115 | 10 | PV | Zip Code 91B |
| 24605 | HESPERIA | 115 | 5 | PV | Zip Code 91B |
| 24606 | PHELAN | 115 | 10 | PV | Zip Code 91B |
| 24607 | ROADWAY | 115 | 10 | PV | Zip Code 91B |
| 24608 | SAVAGE | 115 | 8 | PV | Zip Code 91B |
| 24610 | BLKMTN | 115 | 10 | PV | Zip Code 91B |
| 24622 | PERMANTE | 115 | 10 | PV | Zip Code 91B |
| 24623 | GOLDHILS | 115 | 10 | PV | Zip Code 91B |
| 24815 | GARNET | 115 | 10 | PV | Zip Code 91B |
| 24818 | FARREL | 115 | 10 | PV | Zip Code 91B |

**Table 48 (continued). Incremental Solar Projects Added for 2020 Study Scenario.**

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Added MW Rating** | **Project Type** | **Profile Type** |
| 24902 | VSTA | 66 | 30 | PV | Zip Code 91B |
| 24903 | VSTA | 115 | -6 | PV | Zip Code 91B |
| 25002 | GOODRICH | 33 | 11 | PV | Zip Code 91B |
| 25202 | LEWIS | 66 | 12 | PV | Zip Code 91B |
| 25655 | VIEJO66 | 66 | 31 | PV | Zip Code 91B |
| 26061 | RINALDI | 230 | 21 | PV | Zip Code 900 |
| 26063 | RIVER | 230 | 19 | PV | Zip Code 900 |
| 26068 | STJOHN | 230 | 22 | PV | Zip Code 900 |
| 26076 | FAIRFAX | 138 | 28 | PV | Zip Code 900 |
| 26078 | TOLUCA | 230 | 28 | PV | Zip Code 900 |
| 26081 | ATWATER | 230 | 20 | PV | Zip Code 905 |
| 26085 | HOLYWDLD | 138 | 28 | PV | Zip Code 905 |
| 26086 | NRTHRDGE | 230 | 36 | PV | Zip Code 905 |
| 26088 | OLYMPCLD | 138 | 28 | PV | Zip Code 905 |
| 26093 | TARZANA | 230 | 33 | PV | Zip Code 905 |
| 26102 | VALLEY | 138 | 9 | PV | Zip Code 905 |
| 30430 | FULTON | 230 | 8 | PV | Zip Code 954 |
| 30472 | PEABODY | 230 | 14 | PV | Zip Code 94A |
| 30505 | WEBER | 230 | 10 | PV | Zip Code 95A |
| 30535 | TIDEWATR | 230 | 4 | PV | Zip Code 94A |
| 30545 | ROSSMOOR | 230 | 4 | PV | Zip Code 945 |
| 30554 | CASTROVL | 230 | 15 | PV | Zip Code 945 |
| 30555 | SANRAMON | 230 | 7 | PV | Zip Code 945 |
| 30561 | TASSAJAR | 230 | 4 | PV | Zip Code 945 |
| 30565 | BRENTWOD | 230 | 25 | PV | Zip Code 945 |
| 30585 | LS PSTAS | 230 | 21 | PV | Zip Code 945 |
| 30711 | S.L.A.C. | 230 | 5 | PV | Zip Code 94A |
| 30720 | SARATOGA | 230 | 6 | PV | Zip Code 94A |
| 30730 | HICKS | 230 | 6 | PV | Zip Code 94A |
| 30841 | FIGRDN 1 | 230 | 8 | PV | Zip Code 95A |
| 30846 | FIGRDN 2 | 230 | 4 | PV | Zip Code 95A |
| 30850 | ASHLAN | 230 | 6 | PV | Zip Code 95A |
| 30941 | STCKDLEB | 230 | 5 | PV | Zip Code 95A |
| 30950 | BKRSFLDA | 230 | 5 | PV | Zip Code 95A |
| 30951 | BKRSFLDB | 230 | 14 | PV | Zip Code 95A |
| 31239 | MONROE2 | 115 | 8 | PV | Zip Code 954 |
| 31240 | SNTA RSA | 115 | 12 | PV | Zip Code 954 |
| 31246 | BELLVUE | 115 | 5 | PV | Zip Code 954 |
| 31467 | JESSUP | 115 | 5 | PV | Zip Code 95A |
| 31496 | NORD 1 | 115 | 5 | PV | Zip Code 95A |
| 31498 | SYCAMORE | 115 | 14 | PV | Zip Code 95A |
| 31500 | BUTTE | 115 | 5 | PV | Zip Code 95A |

**Table 48 (continued). Incremental Solar Projects Added for 2020 Study Scenario.**

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| Bus # | Bus Name | kV | Added MW Rating | Project Type | Profile Type |
| 31502 | CHICO B | 115 | 5 | PV | Zip Code 95A |
| 32010 | JAMESON | 115 | 5 | PV | Zip Code 95A |
| 32258 | DMND SPR | 115 | 5 | PV | Zip Code 95A |
| 32263 | CLRKSVLE | 115 | 20 | PV | Zip Code 95A |
| 32265 | SHPRING | 115 | 5 | PV | Zip Code 95A |
| 32971 | MEDW LNE | 115 | 4 | PV | Zip Code 945 |
| 32973 | LAKEWD-C | 115 | 4 | PV | Zip Code 945 |
| 32974 | LAKEWD-M | 115 | 4 | PV | Zip Code 945 |
| 32978 | LMEC | 115 | 9 | PV | Zip Code 945 |
| 33311 | BAY MDWS | 115 | 8 | PV | Zip Code 94A |
| 33312 | BELMONT | 115 | 5 | PV | Zip Code 94A |
| 33370 | REDWOOD | 60 | 5 | PV | Zip Code 94A |
| 33372 | BLLE HVN | 60 | 5 | PV | Zip Code 94A |
| 33548 | TRACY | 115 | 18 | PV | Zip Code 95A |
| 33555 | STKTON A | 115 | 10 | PV | Zip Code 95A |
| 33704 | STAGG | 60 | 7 | PV | Zip Code 95A |
| 33714 | HAMMER | 60 | 6 | PV | Zip Code 95A |
| 33801 | STAGG_5 | 21 | 6 | PV | Zip Code 95A |
| 33803 | STAGG_6 | 21 | 6 | PV | Zip Code 95A |
| 34362 | CLOVIS-1 | 115 | 10 | PV | Zip Code 95A |
| 34364 | CLOVIS-2 | 115 | 10 | PV | Zip Code 95A |
| 34372 | MALAGA | 115 | 8 | PV | Zip Code 95A |
| 34404 | WST FRSO | 115 | 8 | PV | Zip Code 95A |
| 34408 | BARTON | 115 | 7 | PV | Zip Code 95A |
| 34410 | MANCHSTR | 115 | 8 | PV | Zip Code 95A |
| 34414 | WOODWARD | 115 | 7 | PV | Zip Code 95A |
| 34416 | BULLARD | 115 | 7 | PV | Zip Code 95A |
| 34706 | WESTPARK | 115 | 1 | PV | Zip Code 95A |
| 34718 | KERN OIL | 115 | 1 | PV | Zip Code 95A |
| 34736 | MAGUNDEN | 115 | 1 | PV | Zip Code 95A |
| 34752 | KERN PWR | 115 | 5 | PV | Zip Code 95A |
| 34754 | TEVIS | 115 | 5 | PV | Zip Code 95A |
| 34762 | RENFRO | 115 | 20 | PV | Zip Code 95A |
| 34911 | FRUITVLE | 70 | 13 | PV | Zip Code 95A |
| 35062 | DISCOVRY | 13.8 | 10 | PV | Zip Code 95A |
| 35106 | MT EDEN | 115 | 29 | PV | Zip Code 945 |
| 35110 | FREMNT | 115 | 15 | PV | Zip Code 945 |
| 35111 | JARVIS | 115 | 15 | PV | Zip Code 945 |
| 35120 | NEWARK D | 115 | 9 | PV | Zip Code 945 |
| 35350 | AMES BS1 | 115 | 6 | PV | Zip Code 94A |
| 35351 | AMES BS2 | 115 | 5 | PV | Zip Code 94A |
| 35352 | WHISMAN | 115 | 6 | PV | Zip Code 94A |

Table 48 (continued). Incremental Solar Projects Added for 2020 Study Scenario.

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Added MW Rating** | **Project Type** | **Profile Type** |
| 35353 | MT VIEW | 115 | 4 | PV | Zip Code 94A |
| 35354 | STELLING | 115 | 7 | PV | Zip Code 94A |
| 35355 | WOLFE | 115 | 6 | PV | Zip Code 94A |
| 35363 | LAWRENCE | 115 | 6 | PV | Zip Code 94A |
| 35368 | BRITTN | 115 | 4 | PV | Zip Code 94A |
| 35606 | AGNEW | 115 | 6 | PV | Zip Code 95A |
| 35610 | MONTAGUE | 115 | 5 | PV | Zip Code 95A |
| 35612 | TRIMBLE | 115 | 6 | PV | Zip Code 95A |
| 35620 | EL PATIO | 115 | 6 | PV | Zip Code 95A |
| 35622 | SWIFT | 115 | 3 | PV | Zip Code 945 |
| 35624 | MILPITAS | 115 | 6 | PV | Zip Code 945 |
| 35626 | MCKEE | 115 | 6 | PV | Zip Code 95A |
| 35636 | EVRGRN 1 | 115 | 6 | PV | Zip Code 95A |
| 35638 | EDENVALE | 115 | 6 | PV | Zip Code 95A |
| 35646 | MRGN HIL | 115 | 6 | PV | Zip Code 94A |
| 35907 | PAUL SWT | 115 | 31 | PV | Zip Code 94B |
| 35918 | SALINAS2 | 115 | 10 | PV | Zip Code 94B |
| 36420 | STONE | 115 | 6 | PV | Zip Code 95A |
| 37101 | CARMICAL | 69 | 2 | PV | Zip Code 956 |
| 37102 | ELKGROV1 | 69 | 10 | PV | Zip Code 956 |
| 37103 | ELVERTA1 | 69 | 7 | PV | Zip Code 956 |
| 37104 | ELVERTA2 | 69 | 6 | PV | Zip Code 956 |
| 37107 | HEDGE 3 | 69 | 25 | PV | Zip Code 956 |
| 37108 | HURLEY 1 | 69 | 15 | PV | Zip Code 956 |
| 37109 | HURLEY 2 | 69 | 19 | PV | Zip Code 956 |
| 37111 | LAKE 1 | 69 | 8 | PV | Zip Code 956 |
| 37114 | ORANGVL1 | 69 | 3 | PV | Zip Code 956 |
| 37115 | ORANGVL2 | 69 | 3 | PV | Zip Code 956 |
| 37116 | POCKET 1 | 69 | 10 | PV | Zip Code 956 |
| 37117 | POCKET 2 | 69 | 19 | PV | Zip Code 956 |
| 37122 | LAKE 2 | 69 | 8 | PV | Zip Code 956 |
| 37123 | NATOMAS | 69 | 15 | PV | Zip Code 956 |
| 37583 | TRACYPP1 | 13.8 | 5 | PV | Zip Code 945 |
| 37584 | TRACYPP2 | 13.8 | 6 | PV | Zip Code 945 |
| 37649 | LLNLAB | 115 | 11 | PV | Zip Code 945 |
| 37912 | CANBY2 | 12.5 | 5 | PV | Zip Code 959 |
| 37913 | CANBY3 | 12.5 | 16 | PV | Zip Code 959 |
| 37949 | SULP1 | 12.5 | 5 | PV | Zip Code 959 |
| 38028 | PLO ALTO | 115 | 5 | PV | Zip Code 94A |
| 38228 | SNTA CRZ | 115 | 10 | PV | Zip Code 95A |
| 38262 | BRGGSMRE | 69 | 10 | PV | Zip Code 95A |
| 38264 | ENSLEN | 69 | 10 | PV | Zip Code 95A |

**Table 48 (continued). Incremental Solar Projects Added for 2020 Study Scenario.**

| Power Flow Data | | | | | |
|---|---|---|---|---|---|
| **Bus #** | **Bus Name** | **kV** | **Added MW Rating** | **Project Type** | **Profile Type** |
| 38268 | 12TH ST | 69 | 10 | PV | Zip Code 95A |
| 38280 | SYLVAN | 69 | -3 | PV | Zip Code 95A |
| 38314 | STODDARD | 69 | 5 | PV | Zip Code 95A |
| 38460 | CERES | 69 | 6 | PV | Zip Code 95A |

# Appendix C. Application of Solar Data

The assumptions and techniques employed to develop the necessary high-resolution (i.e., 1-minute) profiles for each solar project are described in this appendix. These profiles were used in both the sub-hourly statistical analysis and the QSS analysis. Additional details on those analyses, including the selection of time periods for evaluation, are contained in the body of the report.

**Available Solar Data**

Limited high-resolution solar data was provided for this study. As noted in the main report, the available data was:

- 1-minute data for three years (2002-2004) of net Sungen and Luz plant output (MW)
- 15-minute data for one year (2004) of 13 California zip code based PV profiles (pu)
- 1-minute data for January 2002 and July 2002 of Golden CO irradiation ($W/m^2$)
- 3-minute data for January 2002 and July 2002 of Desert Rock NV irradiation ($W/m^2$)

In addition, the following hourly solar data was available:

- Three years (2002-2004) of net Sungen and Luz plant output (MW)
- Three years (2002-2004) of Stirling project output (MW) for two sites

One year (2004) of California zip code based PV profiles (pu)

Unless otherwise noted, the profiles for a given study time period used data from that time period.

**Development of 1-Minute Profiles**

Three types of profiles were developed for this study – Sungen/Luz based concentrated solar profiles, Stirling engine based project profiles, and zip code based PV profiles.

A simple scaling procedure was used to create concentrating solar project profiles from the net Sungen and Luz data. This procedure was used to create 1-minute profiles for the existing units at those two sites, as well as for any new concentrating solar projects. Projects identified as Stirling engine based were excluded. The procedure consisted of multiplying the data in the desired time period by a factor equal to the project rating divided by the existing net Sungen and Luz rating. An example profile for the combined Sungen and Luz facilities is shown in Figure 178.

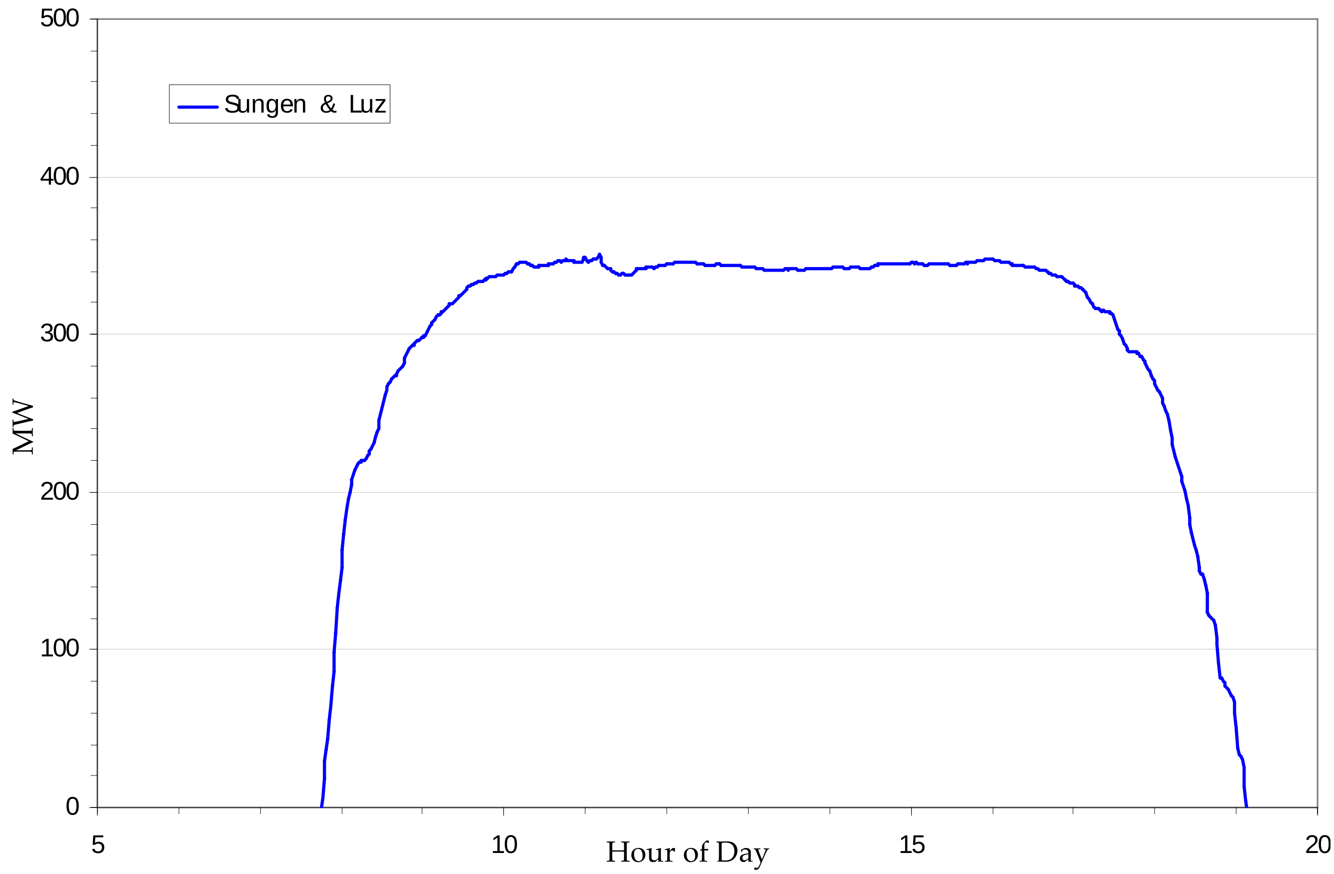


**Figure 178. Example Concentrating Solar Project Profile for a May Day.**

Two new Stirling projects were included in the future study scenarios. Since no high-resolution data was available, the necessary profiles were developed by superimposing the 3-minute Desert Rock NV direct irradiation data on the hourly data. The January irradiation data was used for study periods from November through April, and the July irradiation data was used for study periods from May through October.

The first step in this procedure was to interpolate between the hourly data points to create a ramp rather than a step function.

Next, a rolling 1-hour average of the 3-minute data was calculated. Then, the difference between the 3-minute data and the rolling average was determined and superimposed on the hourly data to create a 3-minute profile. This sum was limited to ensure that the project output did not exceed project rating.

Finally, the 3-minute profile was interpolated to create a 1-minute profile.

A random number generator was used to pick different days of irradiation data for different study intervals and sites. Example profiles for both the 300 MW and 500 MW Stirling projects are shown in Figure 179.

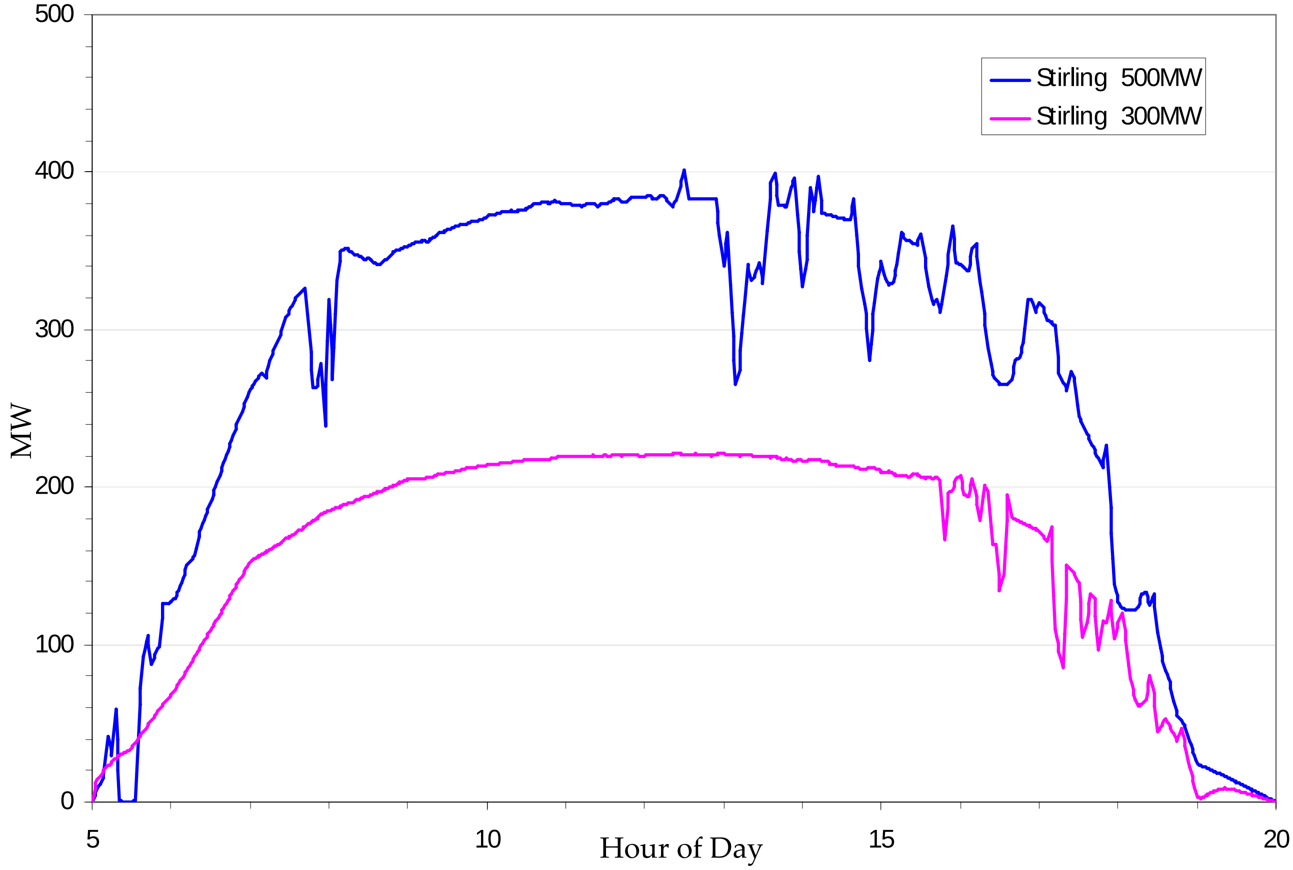

**Figure 179. Example Stirling Solar Project Profile for a May Day.**

More than 200 PV projects were included in some of the future study scenarios. The highest resolution California PV data was based on zip codes and in 15-minute increments. Therefore, each PV site was assigned an appropriate zip code. All PV sites in a given zip code used the same profile.

Since no higher resolution California data was available, the necessary 1-minute profiles were developed by superimposing the 1-minute Golden CO direct irradiation data on the 15-minute California zip code based data. The January irradiation data was used for study periods from November through April, and the July irradiation data was used for study periods from May through October.

The first step in this procedure was to interpolate between the 15-minute data points to create a ramp rather than a step function.

Next, a rolling 15-minute average of the 1-minute data was calculated. Then, the difference between the 1-minute data and the rolling average was determined and superimposed on the 15-minute data to create a 1-minute profile. This sum was limited to ensure that the project output did not exceed project rating.

A random number generator was used to pick different days of irradiation data for different study intervals and zip codes. Example profiles for the 10 zip codes used in the 2010 scenarios are shown in Figure 180.

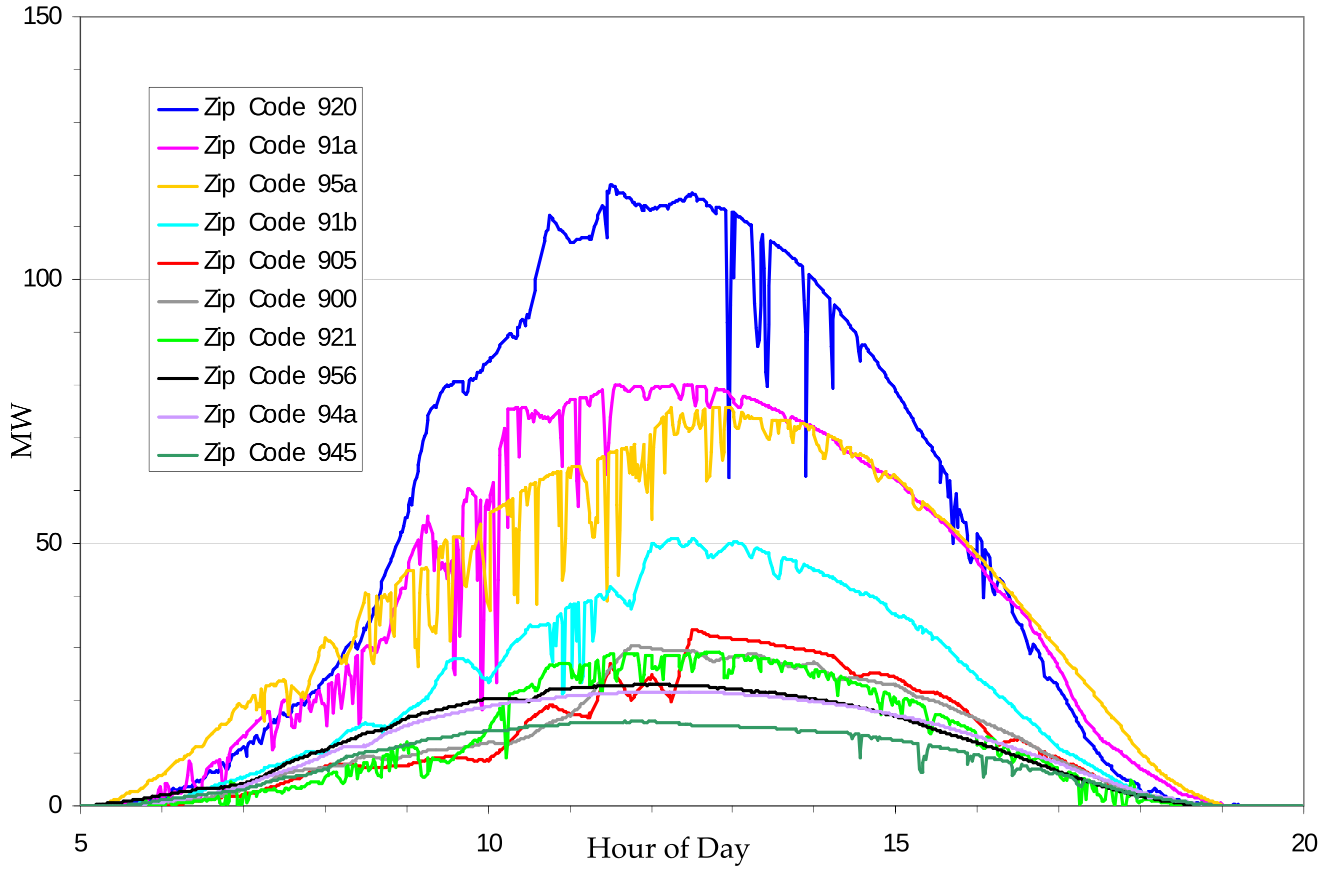


**Figure 180. Example PV Solar ZIP Code Profiles for a May Day.**

Both the Stirling and PV solar profiles have more notches than the Sungen/Luz profile, which is consistent with their relatively short thermal time constants and sensitivity to variable cloud cover.

### Applicability of Out-of-State Solar Data to California PV Sites

A brief statistical evaluation was performed to test the applicability of the Golden CO data to the various California PV sites. First, the difference between each interval in the 15-minute zip code based California data was calculated for the months of January and July. The standard deviation of this 15-minute variability was calculated and is shown in Table 49.

Then, the 15-minute average of the 1-minute Golden CO data was calculated, followed by a calculation of the difference between each 15-minute value. The standard deviation of this 15-minute variability was also calculated and is shown in Table 50.

**Table 49. Standard Deviation of the 15-Minute Variability in the California PV Data.**

| CA Zip Code Based Data (pu) | January | July |
|---|---|---|
| 91A | 0.024 | 0.033 |
| 91B | 0.026 | 0.033 |
| 900 | 0.025 | 0.036 |
| 905 | 0.029 | 0.047 |
| 920 | 0.034 | 0.033 |
| 921 | 0.031 | 0.032 |
| 945 | 0.021 | 0.026 |
| 94A | 0.023 | 0.033 |
| 954 | 0.030 | 0.034 |
| 94B | 0.017 | 0.029 |
| 956 | 0.028 | 0.035 |
| 959 | 0.049 | 0.047 |
| 95A | 0.029 | 0.032 |

**Table 50. Standard Deviation of the 15-Minute Variability in the Golden, CO, Irradiation Data.**

| Golden, CO (pv) | January | July |
|---|---|---|
| 15-min Average | 0.042 | 0.066 |

The standard deviation of the 15-minute variability of the 1-minute Golden data is generally higher than that of the California data. The exception is zip code 959 (covering Yuba, Sutter and other counties) in January, which has the highest standard deviation of any of the California zip codes. Therefore, using the Golden data to provide 1-minute variability is both conservative and credible.

The following example illustrates the procedure for superimposing the 1-minute Golden CO data on the 15-minute California zip code data to create 1-minute profiles for all California PV sites.

Step 1 is to interpolate at 1-minute intervals between the 15-minute data points to achieve a smooth rather than stair step function.

Step 2 is to superimpose the 1-minute variability in global insolation from the Golden data onto the 15-minute interpolated profile. The January data was used for November through April, and the July data was used for May through October. Variability for individual days was applied in a random fashion.

Figure 181 shows the 15-minute data for a July day with 1-minute interpolation (blue line), and the final 1-minute profile including the variability from the Golden data (red line). For reference the 1-minute Golden insolation data used in this example is shown in Figure 182. Note the similarity in the 1-minute variability. Also note that the longer term variability (e.g. 15-minute to an hour) observed around interval 720 in the insolation profile is not superimposed on the

15-minute California zip code data. This is important because the 15-minute variability is already present in the California data, and only the 1-min variability needs to be superimposed.

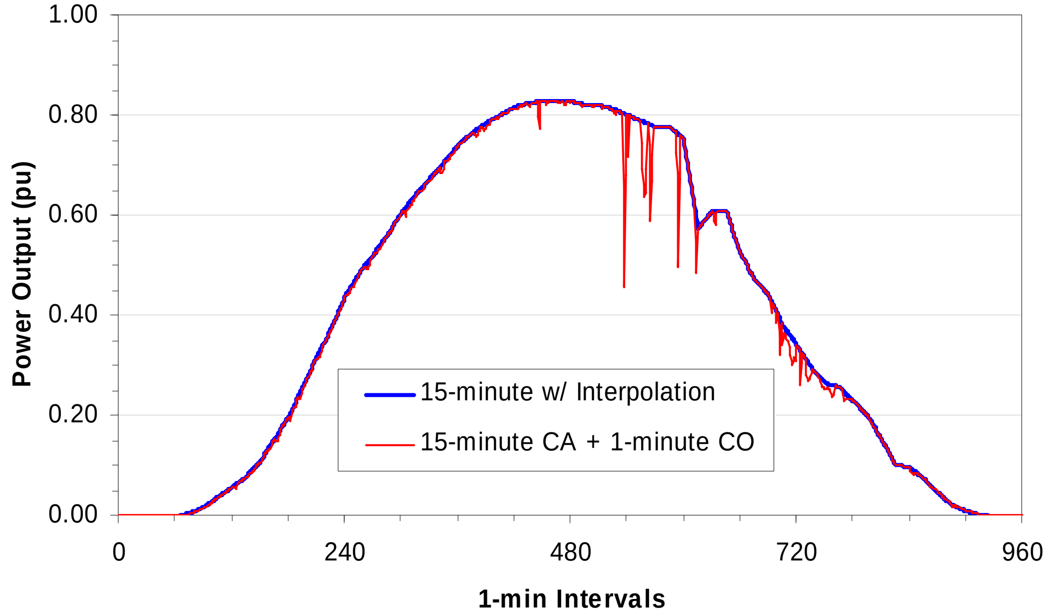


**Figure 181. Comparison of Original 15-Mminute Data and Final Profile with 1-Minute Variability.**

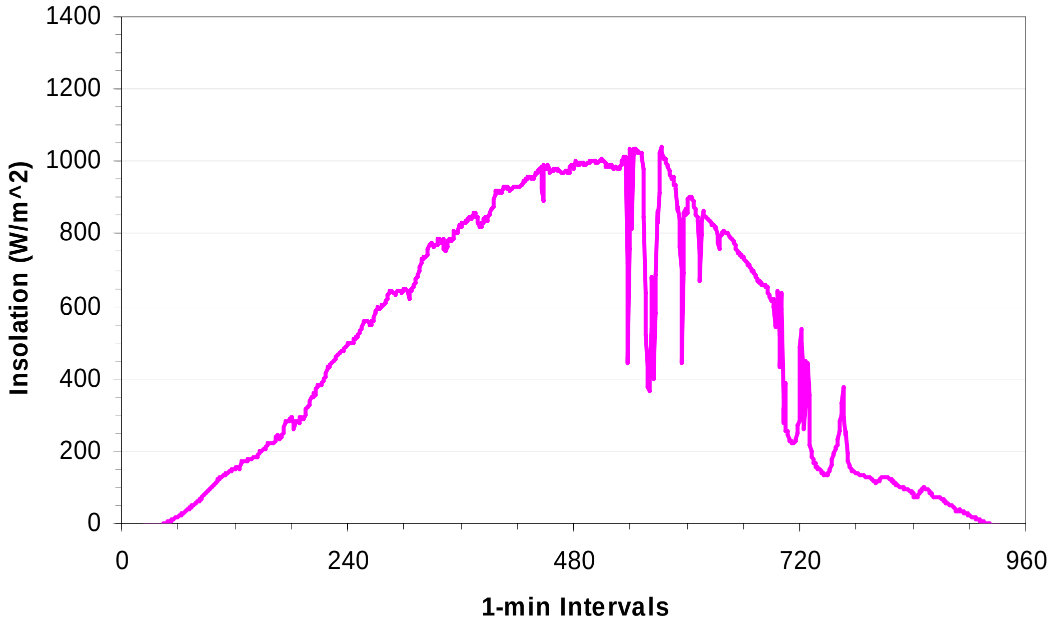


**Figure 182. Irradiation Data Used as Source of 1-Minute Variability in Example.**

Given the paucity of available solar data, this evaluation confirms the reasonableness of using the Golden CO irradiation data to provide 1-minute variability for the California PV sites.